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Midyear Forecast

Magnitude of undiscovered resource in Iraq in dispute
FX Energy drilling in Poland's Permian basin
Gasoline price spike shifts ethylene feeds
Rockies Express faces downstream bottlenecks

OIL&GAS JOURNAL®

July 2, 2007
Volume 105.25

MIDYEAR FORECAST

REGULAR FEATURES

COVER

Demand for oil products is stronger than expected this year, especially demand for gasoline, considering strong pump prices. In its midyear forecast OGJ details the 2007 market for all types of energy consumed in the US and takes a look at worldwide oil supply and demand. Photos on the cover and this page from BP PLC.

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OGJ Newsletter

July 2, 2007

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General Interest — Quick Takes

US, Canadian unconventional gas to aid demand

The trends of declining natural gas well productivity and reserves-to-well ratios are expected to continue through 2015 across all 50 gas basins in the US and Canada, Cambridge Energy Research Associates and IHS reported.

Continued strong market prices will be necessary to motivate enough drilling simply to maintain production on a flat trajectory, said the study, now in its second phase.

In recent years gas production has been buoyed by a shift toward more emphasis on drilling unconventional gas resources such as coalbed methane, gas shale, and tight sandstone.

Study coauthor Robert Ineson, CERA director of North American gas research, said the unconventional gas production stems from "the clear inability of conventional gas resources to keep pace with gas consumption."

Unconventional gas provides solid supply options for several more years, he said. Producers must develop unconventional plays in a cost-effective manner so that gas can compete economically with imported LNG, coal, and other technologies.

"With unconventional resources dominating production trends in the next decade, the performance of existing and emerging unconventional plays will define the long-run supply curve for indigenous North American natural gas supply," Ineson said.

Analysts used a gas price of $4-10/Mcf looking out to 2015 to examine the interplay of future gas production costs, the geological potential in the US and Canada, and how gas supply could build at higher market prices.

The most significant driver of rising gas production costs has been and will continue to be declining production on a per-well basis, not costs for equipment, although equipment costs could push a region to an unprofitable position, the study said.

Of the 15 basins having the largest forecast capacity increases from 2005 to 2010, 12 are primarily unconventional resources, the study said.

Shell to boost biofuels R&D investments

Royal Dutch Shell PLC plans to increase its investment in biofuels research and development to improve energy security and help to lower carbon emissions, a senior executive from the company said June 25 at a press briefing in London.

Rob Routs, Shell executive director, downstream, said the company's focus would be on biofuels—in particular converting waste oils and fats into fuels. This hydrogenated process, Routs said, "is expensive at the moment, but there is some commercial application of it."

Routs declined to say how much the company plans to spend on biofuels R&D, citing company confidentiality. But he did say the company has invested $1 billion in renewable energy over the past 5 years. Higher oil prices are needed to underpin the long-term commerciality of biofuels and experience in developing biofuels plants will also be a critical factor, he said.

Routs called for subsidies or special tax treatments to encourage the construction of biofuels plants, stressing that these were necessary until plants could be developed on a large scale. "We need a few cents/liter [subsidy] to make it work," Routs told OGJ.

Routs has deliberately steered the company away from producing ethanol from sugar cane because he foresaw the difficulty of using food crops for fuels. "I don't think the sugar cane situation in Brazil and the US is sustainable," he said. "If it's picked up for fuel production, there will be a clash and I don't want to get involved in fuel and food competition. Sourcing is a big issue and I don't see us going into owning land collecting waste products to get into this."

Shell has joined German company Choren to launch a new biofuels plant that will convert biomass, such as woodchips, into synthetic fuel, which will then be marketed by Choren as SunFuel. The fuel is being used in diesel engines and can reduce emissions. The 15,000 tonne/year plant is due to become operational in late 2007 or early 2008.

Using waste plant material instead of valuable food crops would help the biofuels industry to circumvent the growing political pressure over using crops for fuel.

Routs told OGJ that Shell is working on various cellulose ethanol initiatives. The US government has promised Canadian company Iogen Corp., which Shell has teamed with, an $80 million grant to build an 18 million gal/year plant in Idaho that will produce cellulosic ethanol from plant waste and straw.

Last year, Shell signed a letter of intent with Volkswagen and Iogen to assess the economic feasibility of producing cellulose ethanol in Germany.

Last year Shell sold more than 3.5 billion l. of biofuels, Routs said.

South Korea confirms gas hydrates deposits

South Korea has confirmed deposits of gas hydrates off the eastern coast of the country, about 135 km northeast of the city of Pohang.

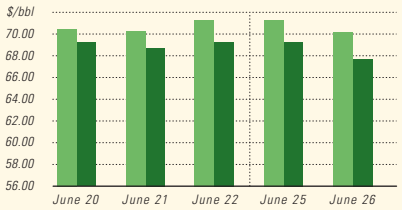
The Ministry of Commerce, Industry, and Energy's oil and gas development division issued a statement June 23 saying the area is within South Korea's exclusive economic zone.

A drilling program, scheduled to begin in September, calls for at least five wells. South Korea hopes to develop the technology for using gas hydrates by 2015, the government said.

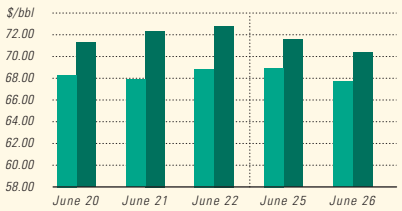
South Korea now imports its oil and natural gas. ✦

Industry Scoreboard

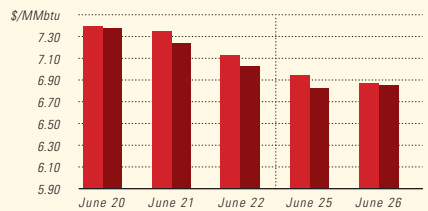
IPE BRENT / NYMEX LIGHT SWEET CRUDE



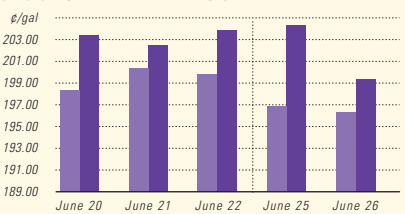
WTI CUSHING / BRENT SPOT



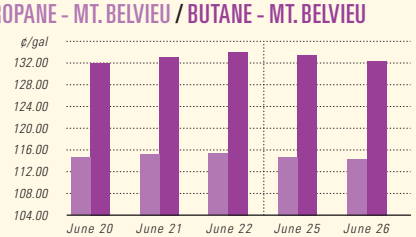
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



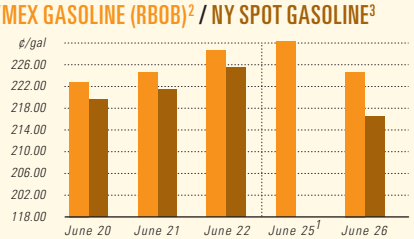
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[2] / NY SPOT GASOLINE[3]



[1]Not available
[2]Reformulated gasoline blendstock for oxygen blending
[3]Nonoxygenated regular unleaded.

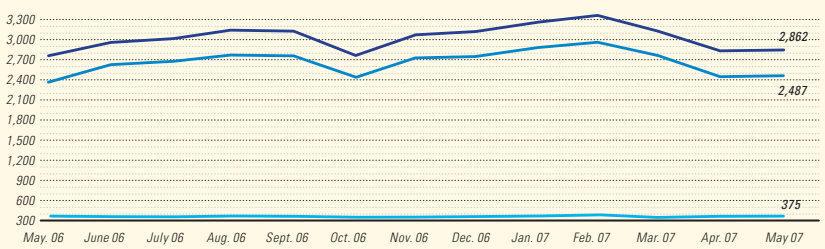
US INDUSTRY SCOREBOARD — 7/2

Latest week 6/22	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,613	9,412	2.1	9,231	9,097	1.5
Distillate	4,115	4,019	2.4	4,318	4,183	3.2
Jet fuel	1,615	1,689	–4.4	1,608	1,604	0.2
Residual	603	599	0.7	743	724	2.6
Other products	4,853	5,068	–4.2	4,947	4,832	2.4
TOTAL DEMAND	20,798	20,787	0.1	20,847	20,440	2.0
Supply, 1,000 b/d						
Crude production	5,162	5,194	–0.6	5,232	5,083	2.9
NGL production[2]	2,323	2,105	10.3	2,379	2,140	11.2
Crude imports	10,160	10,583	–4.0	9,882	10,021	–1.4
Product imports	3,364	3,572	–5.8	3,261	3,555	–8.3
Other supply[3]	1,060	981	8.0	985	1,092	–9.8
TOTAL SUPPLY	22,068	22,435	–1.6	21,739	21,891	–0.7
Refining, 1,000 b/d						
Crude runs to stills	14,750	15,770	–6.5	14,720	15,047	–2.2
Input to crude stills	15,251	16,103	–5.3	15,169	15,388	–1.4
% utilization	88.0	92.6	—	87.5	88.6	—

Latest week 6/22	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	351,037	348,622	2,415	342,800	8,237	2.4
Motor gasoline	201,069	206,336	–5,267	210,398	–9,329	–4.4
Distillate	121,485	123,170	–1,685	126,596	–5,111	–4.0
Jet fuel	39,916	39,971	–55	39,290	626	1.6
Residual	35,540	36,561	–1,021	41,573	–6,033	–14.5
Stock cover (days)[4] **6/15**			**Change, %**		**Change, %**	
Crude	22.8	22.1	3.2	22.1	3.2	
Motor gasoline	21.4	21.3	0.5	22.7	–5.7	
Distillate	29.6	29.4	0.7	30.5	–3.0	
Propane	40.4	35.9	12.5	47.5	–14.9	
Futures prices[5] **6/22**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	68.77	66.82	1.95	69.99	–1.22	–1.7
Natural gas, $/MMbtu	7.42	7.73	–0.31	6.53	0.89	13.6

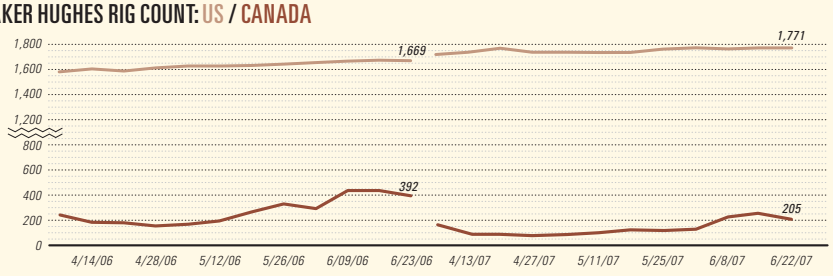
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American Petroleum Institute, Wall Street Journal

BAKER HUGHES INTERNATIONAL RIG COUNT: TOTAL WORLD / TOTAL ONSHORE / TOTAL OFFSHORE



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Noble makes discovery off Equatorial Guinea

Noble Energy Inc. has made a gas and condensate discovery on Block I in the Douala basin off Equatorial Guinea.

The discovery well, I-1, was to test the Benita prospect. The well is 25 miles east of Bioko Island and 13 miles south of the 2005 Belinda discovery on Block O.

I-1, drilled in 2,880 ft of water to 10,460 ft TD, encountered an "extremely" high-quality Miocene reservoir with 135 ft of net hydrocarbon pay, Noble said. The reservoir section at the Benita discovery is much thicker than at Belinda, also of Miocene age.

On test the well flowed 1,038 b/d of condensate and 34.3 MMcfd of gas. Production rates were limited by test facilities.

Condensate yields can be increased with the installation of cooling and processing facilities, Noble said.

Additional appraisal work will be necessary to verify the areal extent of the Benita discovery. Any appraisal work will follow the drilling of an additional exploration well in Block I, Noble said.

The company is currently carrying out a multiwell exploration and appraisal program designed to test a number of prospects in the region.

The Songa Saturn drillship will now move back to Block O to drill later this month a Belinda appraisal well 4.5 miles from the O-1 discovery well. Current plans are to return to Block I in the third quarter to drill the second exploration well.

Noble Energy is the technical operator of Block I with a 40% participating interest.

Oil, gas found in Pakistan's Sindh province

Orient Petroleum Inc. made an oil and natural gas discovery with its Rahim-1 well drilled on Khipro block in Sindh province, Pakistan.

The well, which was spudded Mar. 12, was drilled to 3,200 m. On test the well flowed 800 b/d of oil and 350 Mcfd of gas at 730 psi wellhead flowing pressure through a 32/64-in. choke.

Separately, Oil & Gas Development Co. Ltd. made a gas-condensate discovery on the Thora and Thora East mining lease with the Thora Deep-1 well in Sindh province. The well, which was spudded Nov. 21, 2006, was drilled to 3,906 m. On test, the well flowed 100 b/d of condensate and 9.9 MMcfd of gas at wellhead flowing pressure of 1,880 psi through a 32/64-in. choke.

In addition, OMV Pakistan also made a gas discovery on Gambat Block with the Tajjal-1 well in Sindh province. The well, which was spudded Mar. 16, was drilled to the 3,780 m. The well flowed 20 MMcfd of gas on test.

Statoil proves gas in Algeria's HTJW-1 well

Statoil AS has tested natural gas in Devonian sandstones with its Hassi Tidjerane West (HTJW-1) well in Algeria, the company reported. Statoil is operator of the project.

The well, drilled on the Hassi Mouina license in Algeria's Sahara Desert, is the second exploration well completed and tested there, fulfilling Statoil's license obligations. Statoil did not give the TD of the well or the test production flows.

Statoil, which is working with Sonatrach, finished drilling the first exploration and appraisal well, Hassi Tidjerane 2 (HTJ-2), in March. Statoil holds a 75% interest in Hassi Mouina, and Sonatrach has 25%.

Bill Maloney, senior vice-president for global exploration, said results from both wells were valuable, and that the company would continue with its exploration program to map the resource potential in the block.

"The next location for the [land] rig is Tinerkouk (TNK-1) south in the license, where a third well will be drilled," Statoil said.

The Hassi Mouina license has four blocks within a 23,000-sq-km area in the Gourara basin.

The area lies in the Western Sahara, northwest of the In Salah gas field in which Statoil has a 31.85% interest.

Statoil has a 75% interest in Hassi Mouina, and Sonatrach has 25%.

Apache tests Exmouth basin well off W. Australia

Houston independent Apache Corp. has completed a successful test of Theo 3-H, the first horizontal well at the Van Gogh development in the Exmouth basin 1,175 km off Western Australia.

Theo 3-H was drilled in 1,205 ft of water to a MD of 10,598 ft. It cut a 4,554-ft horizontal section in the Cretaceous Top Barrow formation.

The well flowed 9,694 b/d of oil on test. Its flow rate was restricted by downhole and surface equipment limitations, Apache said.

The company plans to drill 18 additional long-reach horizontal laterals at Van Gogh later this year, with a target of first production by the end of first quarter 2009. At that time, the field is expected to add 20,000 b/d of oil to the company's net production.

The $500 million Van Gogh development will use a floating production, storage, and offloading vessel with a processing capacity of 63,000 b/d and storage capacity of 620,000 bbl. Apache operates the development and owns 52.5% interest in the project, while Tokyo-based Inpex Corp. owns 47.5%.

The Pyrenees development, in which Apache holds 28.57% interest, is expected to add 20,000 b/d of oil to the company's net production as well during 2009. It is anticipated that this field, operated by BHP Billiton Ltd. (71.43%), will receive the formal go-ahead by the end of this month.

Apache currently is drilling the Julimar East-1 appraisal well 3.6 miles northeast of the Julimar-1 gas discovery, which flowed at a combined rate of 85 MMcfd on tests of two Triassic channel sands. Julimar East-1 will appraise the channels tested in the discovery well and will target additional deeper Triassic sands.

Remote Alabama well taps Devonian gas

The Alabama Oil & Gas Board has reported a completion test earlier this year of a modest Devonian gas well off the southern flank of the Black Warrior basin.

EOG Resources Inc., Houston, filed a test rate of 120 Mcfd of gas with 120 psi flowing tubing pressure on a 24/64-in. choke with 118 b/d of water from Devonian perforations at 8,150-8,763 ft. Test date is Mar. 4.

The company's 1 Bayne Etheridge 36-9 well, in 36-20n-2e, Greene County, Ala., is 13 miles south-southeast of Eutaw, Ala. Permitted to 10,350 ft, it went to TD 9,509 ft.

Generalized stratigraphic charts of the Black Warrior basin show two units in the Devonian, the Chattanooga shale underlain by a thicker cherty limestone.

The well site is 40 miles south of nearest Black Warrior basin production in Pickens County and 3 miles northeast of the ARCO Oil & Gas Co. 1 ARCO-Amoco Koch well, drilled to TD 15,600 ft in 10-19n-2e, Greene County, in 1983-84. It was abandoned.

This well site is 140 miles southwest of a budding play for gas in Cambrian Conasauga shale in the Gadsden, Ala., area (OGJ Online, Jan. 23, 2007). ✦

Drilling & Production — *Quick Takes*

Ivanhoe completes Athabasca bitumen test

Ivanhoe Energy Inc. completed an Athabasca bitumen test run at its commercial demonstration plant in Bakersfield, Calif., using HTL, the company's proprietary heavy oil upgrading technology.

The test run was carried out as outlined in a 2000 technology agreement with ConocoPhillips Canada, which provided Ivanhoe with the Athabasca bitumen.

ConocoPhillips Canada has certain nonexclusive capacity rights to use the HTL technology in Canada. The test run was witnessed by a third-party engineer in preparation for Ivanhoe's key investment banking arrangements.

Ivanhoe will use information derived from the test for the design and development of full-scale commercial projects in Western Canada (OGJ, Mar. 27, 2006, Newsletter).

The continuous multiday bitumen trial run was successfully concluded when the feed tank was emptied. The trial demonstrated Athabasca bitumen processing in various HTL modes, including "high yield" and "high quality."

Minke gas field in North Sea begins production

Gaz de France Britain, operator of Minke field in the southern UK North Sea, has begun gas production from a single well subsea development in the field. Minke will produce 60 MMcfd of gas, which will be transported via a 15-km pipeline to the Dutch D15 platform for delivery to Uithuizen in the Netherlands. The well produced as much as 75 MMcfd of gas on test.

GDF Britain, describing Minke's development as a technically and commercially challenging project, said the gas is being delivered from a field that is far from existing infrastructure. It is on Block 44/24a, about 180 km off Norfolk and is adjacent to the UK-Dutch median line in 45 m of water.

Faroe Petroleum (UK) Ltd., a partner in the field, has agreed to buy its equity share of gas under a traditional oil-indexed contract under a gas sales agreement with Gaz de France.

"Minke Main is one of three undeveloped gas field discoveries we acquired in mid-2006 from ConocoPhillips as a package of license interests," Faroe Petroleum said. "The other two undeveloped discoveries in the package are the adjacent Minke Graben, which may be drained through Minke Main, and the Orca gas fields, with two tested discovery wells."

Development decisions on Minke Graben and Orca are anticipated in late 2007 or early 2008.

Ownership interests in Minke field are GDF Britain 15.6%, E.On Ruhrgas UK 42.67%, RWE Dea UK 35.84%, and Faroe Petroleum 5.89%.

Heavy oil production starts at Chetopa field

MegaWest Energy Corp., Calgary, has begun oil production at its demonstration project in Chetopa field, a nonconventional oil development covering 392 acres in Labette County in southeastern Kansas.

The company expects to recover 150,000 bbl of heavy oil from the 15-acre project using thermal recovery. Production currently averages 30-50 b/d from four producing wells. Over the next 3-4 months, this rate is expected to ramp up to 250-300 b/d.

The producing sandstones are analogous to the Bluejacket and Warner sandstones in Missouri, MegaWest said.

The project includes 10 injector sites with twin injectors—one installed above the shale and the other below it, said MegaWest Pres. and Chief Executive Officer George Stapleton.

Of the 20 injector wells in a 10½-acre pattern, the company said 19 are operational. Average depth is 125 ft.

There are 30 production wells in the thermal recovery project. The 26 producers not yet on line are expected to come on stream "as the steam injection operations progress," said David Sealock, vice-president, corporate services.

MegaWest plans to build a natural gas fuel pipeline by October to facilitate a switch to natural gas from motor oil in the steam generator and therefore reduce the project's fuel cost, which amounts to about 66% of total project expenses.

The company has allocated $345,000 of its 2007 budget to the Chetopa development, which is expected to ultimately recover 900,000-1 million bbl of oil, Stapleton said.

The company also has plans to start pilot projects in its other holdings in Kentucky, Texas, and Missouri, he said.

MegaWest has a 100% interest in Chetopa field.

SembCorp Marine units win two jack up contracts

SembCorp Marine Ltd. subsidiary PPL Shipyard has received a $190 million contract to build a jack up drilling rig for Offshore Group Corp., the third rig ordered by the company.

Construction of the rig is expected to start in the third quarter, with delivery scheduled for September 2009, SembCorp said.

In May, SembCorp Marine said its subsidiary Jurong Shipyard, won a $442 million contract to build a drilling and production jack up for Petroprod Ltd., with delivery expected in mid-2010.

SembCorp Marine said the harsh-environment jack up will be built based on the CJ70 design with suitability for operations in the Norwegian sector of the North Sea. ✦

Processing — *Quick Takes*

S-Oil to boost Onsan refinery's paraxylene output

S-Oil Corp. has started a project aimed at increasing paraxylene production at its 520,000 b/cd Onsan refinery and chemical complex in South Korea.

The company has selected ExxonMobil Chemical Technology Licensing LLC's selective PxMax technology, which will allow for an 8% capacity increase without requiring modification of the paraxylene separation process facilities.

The PxMax method produces a paraxylene-enriched mixture that is further processed into sales grade paraxylene. It replaces a nonselective toluene disproportionation process that produced equilibrium mixed xylenes.

BP, DuPont, and ABF propose UK biofuels plants

BP PLC, DuPont, and Associated British Foods have proposed the construction of a 420 million l./year bioethanol plant at Saltend, Hull, UK. The plant is being proposed to help ensure that the UK has 5% of its transportation fuel come from biofuels by 2010. The plant is due to start operations in late 2009 and will use wheat as feedstock.

The partners also plan to develop a 20,000 l./year biobutanol demonstration plant at the same site by early 2009. Investments in the two initiatives are expected to hit $400 million amid growing political pressure to find alternative energy sources for transportation fuels.

"Although initial production would be bioethanol, the partners will look at the feasibility of converting it to biobutanol once the required technology is available," BP said.

The partners are talking to grain trading business Frontier Agriculture about securing locally grown wheat as well as with coproduct marketing company AB Agri in relation to DDGS—a byproduct of bioethanol production. It is expected that formal agreements would be finalized after regulatory approvals are obtained.

Aker Kvaerner and its joint venture partner Praj Industries have won the front-end engineering and design work for the bioethanol plant, with Praj bringing technology and process expertise. The contract follows the companies' recent formation of the BioCnergy Joint Venture, announced June 12.

John Ranieri, head of DuPont Biofuels, said demand was growing significantly for biofuels and it has accelerated the commercial development of biobutanol over the past year.

BP and ABF subsidiary British Sugar would each hold 45% of the plant, with DuPont owning the remaining 10%.

Initial development of biobutanol will start with BP and DuPont sourcing small quantities of biobutanol from China by yearend to test on infrastructure and vehicles.

BP and DuPont launched a partnership last June to develop, produce, and market a next generation of biofuels. ✦

Transportation — *Quick Takes*

Expansions planned for China's Zhoushan oil port

China's National Development and Reform Commission has approved an oil port and storage expansion project at Zhoushan port, Ningbo, in eastern China's Zhejiang province.

NDRC said Zhejiang Jianqiao Energy Development Co. Ltd. will invest 325 million yuan to build the facility, which will include a 50,000-tonne-capacity berth for oil products, a 5,000-tonne-capacity berth, and storage for 290,000 cu m.

The port currently has a throughput capacity of 4 million tonnes/year, NDRC said. However, in May the New China News Agency reported that Zhoushan port handled 2.02 million tonnes of imported crude, up 48.6% from last year. The imports were primarily from the Middle East, the news agency said.

Enbridge again to expand North Dakota pipeline

Enbridge Energy Partners LP, Houston, will conduct a binding open season through Aug. 3 for capacity on the Phase 6 expansion of its North Dakota pipeline system.

The proposed $130 million expansion project, if fully subscribed, would increase system capacity to 155,000 b/d from 110,000 b/d, to be available by yearend.

The system transports oil from western North Dakota and eastern Montana to Clearbrook, Minn., via the Minnesota Pipeline and the Lakehead system. From there shippers can access most major refinery markets along the Great Lakes and in the Midwest and along the US Gulf Coast through current and planned interconnecting pipelines.

Demand has been exceeding eastbound pipeline capacity and there is increased oil production, especially in Richland County, Mont., and western North Dakota oil fields (OGJ, Dec. 11, 2006, p. 42).

Millennium gas pipeline project under way

Millennium Pipeline Co. LLC has begun construction of its 182-mile, 30-in. natural gas pipeline across the Southern Tier and lower Hudson Valley areas of New York.

Construction will continue during the next 2 years, with some restoration work extending into 2009. The pipeline is scheduled to begin service Nov. 1, 2008. It will serve markets along its route and will provide essential service to the New York City markets through its pipeline interconnections.

The project initially was expected to be commissioned late this year, but the in-service date was pushed back due to project delays (OGJ Online, July 17, 2006).

Phase 1 of the project will transport 500 MMcfd of gas from the Dawn, Ont., trading hub and several supply and storage basins. It includes the upgrade of a 186-mile Corning-Ramapo, NY, pipeline section on Millennium, which will replace an existing line of Columbia Gas Transmission Corp., and an 83-mile extension of the 24-in. Empire system from a point near Rochester to Corning, NY. Empire connects to the TransCanada PipeLines Ltd. system at Chippawa on the US-Canada border.

The Millennium Pipeline is jointly owned by affiliates of NiSource Inc., KeySpan Corp., and DTE Energy. ✦

Letters

Darfur item challenged

I find Eric Watkins' nearly frivolous appraisal of the deadly serious situation in the Darfur region of Sudan both incredible and reprehensive (OGJ, May 21, 2007, p. 31). While I am sure that both Beijing and Khartoum greatly appreciate his terminology ("alleged genocide"), those unfortunate individuals who have been brutally treated by the death squads would not.

I hope that Mr. Watkins takes a more sensitive and balanced approach in the future to similar humanitarian disasters—no matter how bad it makes our industry or foreign governments look.

Joe George
Chevron Texaco Richmond Refinery
Richmond, Calif.

Sending messages

I read in Oil & Gas Journal a quote from Senate Majority Leader Harry Reid (D-Nev.): "The mere fact we're moving legislation on the floor should send a message to oil cartels" (OGJ, June 4, 2007, p. 28).

Oh, it sends a message all right. All of the provisions passed by the US House and Senate will do nothing to increase supplies of crude oil and refined products to American consumers. As a matter of fact, these legislative attempts to "punish" petroleum producers further restrict supplies, cause more volatility in the market, and probably will raise prices to consumers.

The nation's energy debate is not about increasing supplies but about punishing an industry that has provided a safe, reliable, and affordable product to consumers worldwide. The "message," as Sen. Reid put it, and intent are to put the American oil industry out of business.

Now is the time to write your congressman and senators to express your opinions about the actions of the House and Senate. The Texas Alliance of Energy Producers has kicked into high gear our efforts in Washington, because even though the Alliance is not an oil cartel we got the message loud and clear.

Alex Mills, President
Texas Alliance of Energy Producers
Wichita Falls, Tex.

Calendar

✦ Denotes new listing or a change in previously published information.

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Additional information on upcoming seminars and conferences is available through OGJ Online, Oil & Gas Journal's Internet-based electronic information source at http://www.ogjonline.com.

2007

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✦International Offshore and Polar Engineering (ISOPE) Conference & Exhibition, Lisbon, (650) 254-1871, (650) 254-2038 (fax), e-mail: meetings@isope.org, website: www.isope.org http://www.isope.org/. 1-6.

IPAA OGIS, London, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 11.

Carbon Sequestration Development & Finance Summit, Houston, (818) 888-4444, website: www.infocastinc.com/sequest07.html. 11-13.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 18-20.

Purvin & Gertz Annual Asia LPG Seminar, Singapore, (713) 236-0318, (713) 236-8490 (fax), e-mail: glrodriguez@purvingertz.com, website: www.purvingertz.com. 25-28.

West China International Oil & Gas Conference, Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-27.

International Petroleum & Petrochemical Exhibition, Urumqi, Xinjiang, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 26-28.

AUGUST

Coal-Gen Conference, Milwaukee, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 1-3.

Diesel Engine-Efficiency and Emissions Research (DEER) Conference, Detroit, (540) 937-1739, e-mail: kim@cemamerica.com, website: www1.eere.energy.gov/vehiclesandfuels/resources/conferences/deer/index.html. 12-16.

Rocky Mountain Natural Gas Strategy Conference & Investment Form, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: cogaconference@aol.com, website: www.coga.org. 13-15.

American Chemical Society National Meeting & Exposition, Boston, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 19-23.

NAPE Summer Expo, Houston, (817) 847-7700, (817) 847-7703 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 23-24.

IADC Well Control of the Americas Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 28-29.

SEPTEMBER

Brasil Subsea Conference & Exhibition, Rio de Janeiro, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwellpetroleumgroup.com. 1.

SPE/EAGE Reservoir Characterization and Simulation Conference, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-5.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 4-6.

Offshore Europe Oil & Gas Conference and Exhibition, Aberdeen, +44 (0) 208 439 8890, +44 (0) 208 439 8897 (fax), e-mail: oe2007@spearhead.co.uk, website: www.offshore-europe.co.uk. 4-7.

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The oil story in numbers

Bob Tippee
Editor

For most of its 105 years in print, Oil & Gas Journal has published multiple series of industry statistics.

In formats that have varied through the years, the numbers have covered industry functions such as production, drilling activity, and refinery operations. Oil and gas prices, too, long have been part of the numerical picture OGJ presents of the industry it covers.

Inevitably, the data series themselves have evolved. Sources change. New data series emerge, and some lose relevancy and expire.

OGJ's statistical offering now is more comprehensive than ever. It's also complex. Some tables in the Statistics section appear every week, but some appear only once a month. While not as confusing as it might seem, the schedule bears repeating from time to time.

For many years, the weekly tables have included US data from the American Petroleum Institute on imports of crude and products, crude and product stocks, and refinery operations. Other weekly tables come from several sources and include crack spreads; prices of gasoline, US and world crude, and refined products; production of crude oil and lease condensate; the Baker Hughes and Smith rig counts; and US natural gas storage.

The schedule

Monthly data, of course, need special scheduling.

The first issue of each month offers Pace refining margins, worldwide NGL production, US natural gas balance, oxygenates, and US heating and cooling degree days.

The second issue of the month includes a full-page table of worldwide oil and gas production, by country.

On the third week, OGJ's Statistics section presents the international rig count, oil import freight costs, US LNG imports, the Baker Oil Tools workover rig count, propane prices, and four tables from Muse, Stancil & Co. on margins: refining, gas processing, ethylene, and marketing.

Fourth-week offerings are the world oil balance, OECD net oil imports, OECD imports from OPEC, oil stocks in OECD countries, and US petroleum imports by source country.

One further wrinkle complicates this schedule. OGJ is published every Monday except for the last Monday of the year and on fifth Mondays of the three or four months each year that have them. Weekly tables that would appear in OGJ's dark Mondays double up with their counterparts on following Mondays.

As OGJ Statistics Editor Laura Bell—probably the only person on Earth who can recite this schedule from memory—can attest, the program covers a lot of numbers. Historical series for most of them are available for purchase through the OGJ Online Research Center, a link to which appears on the left side of OGJ Online's home page (www.ogj.com).

Nothing stays the same, though. Changes are coming to OGJ's statistical reporting.

Starting July 16, API data on imports, stocks, and refinery operations will give way to numbers on the same subjects from the US Energy Information Administration. Other than minor differences in a few subcategories, the tables will change little.

The main difference will be timing. OGJ's reporting lag with API has been about a week and a half. API data in this week's issue thus are for the week that ended June 22.

The reporting lag for EIA statistics on imports, stocks, and refining will be a week longer than that. When the new EIA series start July 16, the numbers will be for the week that ended June 29. The numerical vintages for these operational categories then will match those of OGJ's three other weekly data series from EIA: refined product prices, world crude prices, and US gas storage.

Historical series in the new EIA data categories, unlike those for the API series they replace, are available in the Online Research Center.

New table

Another change will appear in the Statistics section July 16.

The section will include a new monthly table from Waterborne Energy, Houston, on US imports of LNG. It will replace the monthly table of similar data from EIA. In this case, the reporting lag will shrink to 1½ months from 2½ months. Otherwise, the table will be like the one it replaces, showing imports by country of origin.

As long as numbers remain vital pieces of the oil and gas story, OGJ will report statistics—even if people other than OGJ's busy statistics editor need a printed program to know what numbers will appear on a given week in those tan pages at the back of the magazine. ✦

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Editorial

Energy veto bait

The US Congress has acted out many of its demagogic whims on energy. A few more are in prospect. Veto season looms.

With energy bills already passed, the House and Senate clearly want more to punish an unpopular industry than to act constructively on energy. To oil and gas companies, the proposals would be damaging if enacted but not ruinous. To the consumers and taxpayers who would pay for the blunders, harm would be far worse.

Only in a perversely political context can this bundle of historically discredited ideas make any kind of sense. Maybe congressional Democrats intend to send President George W. Bush a bill they know he'll veto so they can scorn him as a friend of Big Oil. What a way to govern.

Bush isn't running for anything. Even though it's the start of what promises to be a vitriolic presidential campaign, he should do what's right for the country instead of what he thinks might help his political party, a large part of which is fleeing him anyway. He has nothing politically to lose. His country has much to lose if he doesn't defend it against the worst products of antioil populism.

By approving energy legislation in present form, Congress would be ignoring lessons of the past and discouraging oil and gas investment in a country that craves new supply. Each of the following measures, passed in some form by one or both houses of Congress, represents a reason for Bush to veto whatever mess reaches the White House:

- Making "price-gouging" in supply emergencies a crime. This would be a law against behavior Congress can't define, enforcement of which would amount to imposition of price controls. Results would be diminished investment in new supply and constrained sales in emergencies, just what consumers don't need.
- Extending antitrust enforcement to the Organization of Petroleum Exporting Countries. Like the price-gouging initiative, this measure would restrict sales and discourage development of future supply, but the effects would appear outside the US. Inside the US, consequences would be the same: lower supply and higher price.
- Asking the government to determine how much and what kinds of energy people use. Government shapes the energy market at best by guessing and at worst by dispensing political favors. Energy consumers and economies always suffer when governments tinker with markets.
- Raising taxes on the oil and gas industry. Tax hikes reduce capital available for investment in supply. They also improve the relative allure of opportunities elsewhere. A legislature serious about its expressed concern over foreign oil would seek ways to cut taxes on domestic production and refining, however unpopular such a move would be while gasoline prices are high.
- Rescinding contracts and incentives. A political regime that erodes long-term project economics with short-term fiscal changes frightens capital. It's understandable that lawmakers want to change deepwater leases containing royalty incentives to insert price thresholds omitted in 1998 and 1999. But the leases are contracts, and producers entered them in good faith. To hold participation in future lease sales hostage to renegotiation of the troublesome leases reflects bad faith by the government. So do efforts to eliminate production incentives enacted in the Energy Policy Act of 2005 (EPACT) after less than 2 years. Political stability is an advantage in competition for exploration and production capital. The US can't afford to squander it.
- Increasing the ethanol mandate. That the EPACT ethanol mandate was a mistake becomes clearer with time to everyone except the grain growers and distillers getting rich from it. Expanding the mandate would aggravate problems rapidly becoming manifest in the prices of food and fuel.

On ethanol, of course, Congress is mainly following the president, who in his state-of-the-union speech urged a quintupling of the mandate and won't see a comparable initiative as objectionable. But Congress seems determined to send Bush energy legislation with plenty of other reasons for him to exercise the veto. To the great fortune of energy consumers and taxpayers, one reason is all that's necessary. ✦

Economic growth boosting US, global energy demand

Marilyn Radler
Senior Editor-Economics

Laura Bell
Statistics Editor

Energy demand will increase in the US and worldwide this year as the global economy continues to grow.

In the US, consumption rates for natural gas, oil, coal, and nuclear energy consumption all will climb, but the use of energy from renewable sources will decline slightly.

A gain in US LNG imports will offset a decline in gas imported from Canada, and US gas production will post a small increase this year as demand rebounds after last year's drop.

The oil market will remain healthy, and US demand for most petroleum products will grow. Inventories of gasoline in the US are tight and look to remain so in the second half of this year, keeping crude and product prices strong. Refinery utilization will increase marginally.

As a result of increased domestic crude production and a small hike in oil demand, US dependence on oil imports will fall slightly from its level of 2006.

Worldwide trends

Worldwide oil demand will climb 2% to an average of 86.1 million b/d this year, according to the International Energy Agency, Paris. The agency forecasts that demand will peak in the fourth quarter, averaging 88 million b/d.

The market will need more crude from the Organization of Petroleum Exporting Countries this year because little oil production growth is expected from countries outside the organization.

IEA figures show that most demand growth will take place in countries outside the Organization for Economic Cooperation and Development. Leading the non-OECD growth will be China, with average demand of 7.59 million b/d, up from 7.16 million last year. Total non-OECD demand will climb 1.3 million b/d this year.

OECD oil demand will climb to 49.6 million b/d from an average of 49.2 million b/d last year. Demand in North America will grow 490,000 b/d, and Canada and Mexico will each register small increases in demand for oil products. Demand in OECD Europe and Pacific countries will decline slightly this year.

OGJ forecasts that worldwide oil supply will average 86 million b/d this year. This assumes that OPEC crude supply rises to average 31 million b/d in the third quarter and 32 million b/d in the fourth quarter. In the first half of 2007, the organization's members—including Angola, which joined effective

Jan. 1—supplied about 30.2 million b/d on average.

OPEC has not officially adjusted its output ceiling since it implemented a planned 500,000 b/d reduction at the start of February 2007. Recent comments from OPEC officials indicate that the organization has no plans to consider a new ceiling before its scheduled September meeting, in spite of high prices. OPEC continues to say that market tightness is the result of refining problems, not crude supply.

Supply from OECD countries will be unchanged this year at 20 million b/d as a dip in European production offsets a small increase in North America.

The former Soviet Union will lead 2007 non-OECD supply growth, according to IEA. The agency expects Russia's crude and condensate production to average 9.95 million b/d, up 2.6% from last year.

With total non-OPEC supply declining to average 50.2 million b/d this year from 50.8 million b/d and worldwide demand rising, the call for OPEC crude escalates.

Oil prices

In its June 2007 Oil Market Report, IEA said, "While it is clear that much of the recent rise in crude prices has been caused by US gasoline tightness, there is a portion which is related to tighter OPEC supply. Hopes for a moderation in crude prices in the short term therefore lie both with OPEC and the US gasoline market."

With limited spare oil production capacity and supply disruptions, world crude prices have climbed since the start of 2007. Hostilities in Nigeria—with attacks on pipelines, pumping stations, and offshore vessels—have reduced production levels there.

The price of Nigerian Bonny Light crude on June 1 was $71.04/bbl, up from $60.64/bbl on Jan. 1. The recent price was still slightly below its year-earlier level. Brent Blend crude from the UK and Mexico's Isthmus crude followed the same price pattern as Bonny Light. Meanwhile, Arabian Light crude on June 1 was up 21% from its Jan. 1 price and a bit higher than its year-earlier price.

Although they have been trending upwards since January, on average 2007 crude prices have declined from a year ago on the New York Mercantile Exchange. For the first half of this year, the front-month contract closed at an average of $61.60/bbl vs. $67.13/bbl in the first half of last year.

OGJ expects the average cost of crude this year for US refiners to decline about 5% from last year's average of $60.23/bbl. Compared with the first half of 2006, refiners' crude costs were down about 7% in the first half of this year.

Refiners have benefitted from sour crude oil discounts relative to light sweet crudes. The combination of plentiful supplies of sour grade crude and greater demand for sweet crudes has maintained a discount to West Texas Intermediate as refiners must meet lower sulfur specifications for cleaner fuels.

Product prices

Retail prices of motor gasoline and heating oil stand poised to reach record average levels for 2007, breaking the records they set last year. Refinery problems in the US coupled with

WORLDWIDE OIL SUPPLY AND DEMAND

Table 1

	2006 1st Qtr.	2006 2nd Qtr.	2006 3rd Qtr.	2006 4th Qtr.	2006 Year	2007 1st Qtr.	2007 2nd Qtr.	2007 3rd Qtr.	2007 4th Qtr.	2007 Year
	Million b/d									
DEMAND										
OECD										
North America	25.2	25.1	25.5	25.4	25.3	25.7	25.4	25.9	26.0	25.8
Europe	15.8	15.1	15.5	15.6	15.5	15.1	15.0	15.6	15.8	15.4
Asia/Pacific	9.3	7.9	7.9	8.8	8.5	8.9	7.9	8.0	8.9	8.4
Total OECD	**50.3**	**48.0**	**48.9**	**49.7**	**49.2**	**49.7**	**48.2**	**49.6**	**50.8**	**49.6**
Non–OECD										
FSU	3.9	3.7	4.0	4.3	4.0	3.8	3.6	4.1	4.4	4.0
Europe	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8
China	7.0	7.3	7.2	7.2	7.2	7.3	7.7	7.6	7.7	7.6
Other Asia	8.9	8.9	8.6	8.8	8.8	9.1	9.2	9.0	9.2	9.1
Latin America	5.1	5.3	5.4	5.4	5.3	5.3	5.5	5.6	5.5	5.5
Middle East	6.2	6.2	6.5	6.3	6.3	6.4	6.5	6.8	6.5	6.6
Africa	3.0	3.0	2.9	2.9	2.9	3.1	3.1	3.0	3.1	3.1
Total non–OECD	**34.9**	**35.2**	**35.2**	**35.7**	**35.2**	**35.8**	**36.3**	**36.7**	**37.3**	**36.6**
TOTAL DEMAND	**85.1**	**83.2**	**84.1**	**85.4**	**84.5**	**85.6**	**84.6**	**86.3**	**88.0**	**86.1**
SUPPLY										
OECD										
North America	14.2	14.2	14.3	14.3	14.2	14.4	14.2	14.2	14.3	14.3
Europe	5.5	5.1	4.9	5.2	5.2	5.2	5.0	5.0	5.2	5.1
Asia	0.5	0.5	0.7	0.6	0.6	0.6	0.6	0.7	0.7	0.6
Total OECD	**20.2**	**19.8**	**19.9**	**20.1**	**20.0**	**20.2**	**19.9**	**19.8**	**20.2**	**20.0**
Non–OECD										
FSU	11.8	12.0	12.2	12.4	12.1	12.5	12.5	12.5	12.7	12.6
Europe	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.7	3.7	3.7	3.6	3.7	3.7	3.7	3.7	3.8	3.7
Other Asia	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Latin America	4.3	4.4	4.4	4.4	4.4	4.4	4.4	4.5	4.6	4.5
Middle East	1.8	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.6
Africa	3.9	3.8	3.9	4.1	3.9	2.6	2.6	2.7	2.7	2.6
Total non–OECD	**28.3**	**28.5**	**28.7**	**29.0**	**28.7**	**27.8**	**27.8**	**27.9**	**28.2**	**27.9**
Processing gain	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Other biofuels	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.4	0.4
Total non–OPEC	**50.7**	**50.5**	**50.7**	**51.3**	**50.8**	**50.3**	**50.0**	**50.0**	**50.7**	**50.2**
OPEC[1]										
Crude	29.9	29.7	30.0	29.2	29.7	30.2	30.2	31.0	32.0	30.9
NGL	4.6	4.6	4.6	4.7	4.6	4.8	4.8	4.8	5.0	4.9
Total OPEC	**34.5**	**34.3**	**34.7**	**33.9**	**34.3**	**35.0**	**35.0**	**35.8**	**37.0**	**35.8**
TOTAL SUPPLY	**85.1**	**84.8**	**85.4**	**85.2**	**85.1**	**85.3**	**85.0**	**85.8**	**87.7**	**86.0**
Stock change	—	1.5	1.3	–0.3	0.7	–0.3	0.4	–0.5	–0.3	–0.1

[1]Includes Angola beginning 2007. Totals may not add due to rounding.
Source: International Energy Agency; OGJ estimates for OPEC 2nd, 3rd, and 4th quarter 2007 crude supply.

OGJ FORECAST OF US OIL SUPPLY AND DEMAND

Table 2

	First half 2007 Volume 1,000 b/d	First half 2007 % change from 2006	Year 2007 Volume 1,000 b/d	Year 2007 % change from 2006
DEMAND				
Motor gasoline	9,220	1.4	9,350	1.3
Dist. 1–4	7,583	1.4	7,704	1.3
Dist. 5	1,637	1.4	1,646	1.3
Jet fuel	1,625	1.3	1,640	1.0
Dist. 1–4	1,142	1.3	1,148	1.0
Dist. 5	483	1.3	492	0.8
Distillate	4,280	2.3	4,275	2.4
Dist. 1–4	3,711	2.3	3,690	2.4
Dist. 5	569	2.3	585	2.4
Residual	810	11.9	780	14.5
Dist. 1–4	632	11.9	598	14.5
Dist. 5	178	11.9	182	14.5
LPG and ethane	2,200	6.0	2,100	2.7
Dist. 1–4	2,144	6.0	2049	2.7
Dist. 5	56	6.0	51	2.7
Other products	2,730	–1.0	2,777	–2.0
Dist. 1–4	2,474	–1.0	2493	–2.0
Dist. 5	256	–1.0	284	–2.0
Total domestic demand	**20,865**	**2.1**	**20,922**	**2.2**
Dist. 1–4	17,685	2.1	17,681	2.3
Dist. 5	3,180	1.9	3,241	1.9
Exports	**1,300**	**1.9**	**1,370**	**2.7**
Dist. 1–4	1,047	1.9	1139	2.7
Dist. 5	253	1.9	231	2.7
Total demand	**22,165**	**2.1**	**22,292**	**2.2**
Dist. 1–4	18,733	2.1	18,820	2.3
Dist. 5	3,432	1.9	3,472	1.9
SUPPLY				
Domestic production				
Crude & condensate	5,177	1.8	5,200	1.2
Dist. 1–4	3,665	1.8	3,763	1.2
Dist. 5	1,512	1.8	1,437	1.2
NGL and other hydrocarbons	1,745	1.8	1,760	1.4
Dist. 1–4	1,674	1.8	1,693	1.4
Dist. 5	71	0.4	67	1.4
Total domestic production	6,922	1.8	6,960	1.3
Dist. 1–4	5,338	1.8	5,456	1.3
Dist. 5	1,584	1.8	1,504	1.3
IMPORTS				
Crude oil	10,000	–0.2	10,200	1.1
Dist. 1–4	8,852	–0.2	9,013	1.1
Dist. 5	1,148	–0.2	1,187	1.1
Products & unfinished oils	3,550	–0.1	3,560	1.3
Dist. 1–4	3,281	–0.1	3,256	1.3
Dist. 5	269	–0.1	304	1.3
Total imports	**13,550**	**–0.2**	**13,760**	**1.1**
Dist. 1–4	12,134	–0.2	12,269	1.1
Dist. 5	1,416	–0.2	1,491	1.1
Processing gain, loss, etc.	1,671	24.1	1,550	3.8
Dist. 1–4	1,353	24.1	1,255	3.8
Dist. 5	318	24.1	295	3.8
Total new supply	**22,143**	**2.0**	**22,270**	**3.7**
Dist. 1–4	18,825	1.8	18,981	1.4
Dist. 5	3,318	2.7	3,289	1.4
Stock change	**–22**	—	**–22**	—
Dist. 1–4	92	—	161	—
Dist. 5	–114	—	–183	—
Crude runs to stills	**15,085**	**0.3**	**15,510**	**1.8**
Total Input to stills	**15,400**	**0.1**	**15,780**	**1.2**
Total refining capacity	**17,460**	**0.5**	**17,500**	**0.7**
Refining utilization, %	**88**	**–0.4**	**90**	**0.5**
Total industry stocks*	**1,010**	**–3.1**	**1,010**	**–2.1**
Refined products	667	–5.4	700	–3.0
Crude oil	343	2.1	310	—
SPR crude oil stocks	691	0.4	700	1.6
IMPORT DEPENDENCY				
Total imports % domestic demand	64.9	—	65.8	—
Net imports % domestic demand	58.7	—	59.2	—

*Million bbl at end of period.

strong demand pressured inventories of gasoline throughout the first half of this year, bolstering prices.

Pump prices for all types of gasoline this year will climb, averaging $2.70/gal. Last year's average pump price across all types of gasoline was $2.635/gal, according to EIA. The peak month last year was July, with an average price of $3.046/gal.

Taxes on regular unleaded self-serve gasoline currently average 43.6¢/gal nationally, up from 42.4¢/gal at the start of last year.

OGJ forecasts that the price of residential heating oil excluding taxes will average $2.40/gal this year. The price averaged a bit higher in the first quarter of this year than during the corresponding 2006 quarter. For all of 2006 heating oil excluding taxes averaged $2.362/gal.

Gas prices

The average US wellhead natural gas price this year will be $7.00/Mcf, up from $6.42/Mcf a year ago.

Gas prices began the year slightly lower than their levels of a year ago. There was plenty of gas in storage, and the number of heating-degree days in January and March was below normal.

In the second quarter, gas futures prices on the NYMEX began to rise amid expectations for an active Atlantic hurricane season and warmer summer temperatures.

During May the closing price of the front-month contract for gas averaged $7.822/MMbtu. During May 2006, the average for the near-month gas contract was $6.373/MMbtu.

US energy

Real gross domestic product, the output of goods and services produced in the US, increased at an annual rate of 0.6% in the first quarter of 2007, according to preliminary estimates by the Bureau of Economic Analysis. That was less than half the growth rate BEA had predicted earlier and followed a fourth-quarter 2006 growth rate of 2.5%/year.

Although GDP growth has slowed from last year, many economic indica-

tors remain positive for growth.

Real personal consumption expenditures increased 4.4% in the first quarter of 2007, compared with an increase of 4.2% in the fourth quarter of last year. Excluding energy and food prices, US inflation has been little changed this year, and unemployment remains low.

In May, the consumer price index rose just 0.7%, and unemployment was 4.5%, according to the US Department of Labor's Bureau of Labor Statistics. First-quarter 2007 productivity in the nonfarm business sector picked up 1% from the fourth quarter of 2006.

OGJ forecasts that GDP this year will grow 2%. Last year's growth rate was 3.3%. Some of the pull on economic growth so far this year has been the weak housing market.

With this year's increase in economic activity there will be a small increase in energy consumption. Total energy demand in the US will grow 1.6%. Since this pace is below the rate of growth in GDP, energy efficiency will improve to 8,699 btu/$ of GDP from 8,730 btu/$ during 2006.

Energy sources

Total energy demand in the US will be 101.26 quadrillion btu (quads) this year. Use of most sources of energy will increase from last year, but a decline in the use of hydroelectric power will result in a decrease in total demand for energy from renewable sources. Natural gas will account for a larger share of the energy mix, while oil, coal, and nuclear energy are nearly unchanged from their 2006 shares.

Oil will remain the largest component of the energy mix at 40.4%. US demand for petroleum products will increase 1.6% this year and total 40.86 quads. Consumption of all the major products will exceed last year's.

The energy source that will grow the most this year is gas, demand for which will climb 3% and represent 22.9% of the US energy market. Larger gas deliveries to residential customers and electric power providers will propel demand.

First quarter worldwide oil production

Table 3

Country	First quarter 2007	First quarter 2006	Change	Change, %
	1,000 b/d			
OPEC*	**30,228**	**29,657**	**571**	**1.9**
Non–OPEC	**42,250**	**43,065**	**–815**	**–1.9**
Argentina	633	621	12	1.9
Brazil	1,754	1,692	62	3.7
Canada	2,621	2,495	126	5.1
Colombia	518	530	–12	–2.3
Ecuador	499	547	–48	–8.8
Mexico	3,158	3,344	–186	–5.6
United States	5,190	5,037	153	3.0
Other	2,798	3,014	–216	–7.2
Western Hemisphere	17,171	17,280	–109	–0.6
Norway	2,425	2,629	–204	–7.8
United Kingdom	1,595	1,670	–75	–4.5
Other	607	625	–18	–2.9
Western Europe	4,627	4,924	–297	–6.0
FSU	12,151	11,400	751	6.6
Other	179	185	–6	–3.2
Eastern Europe & FSU	12,330	11,585	745	6.4
Egypt	660	693	–33	–4.8
Gabon	230	240	–10	–4.2
Other	8,567	8,318	249	3.0
Africa	9,227	9,011	216	2.4
Oman	723	753	–30	–4.0
Syria	393	440	–47	–10.7
Other	20,601	21,362	–761	–3.6
Middle East	21,717	22,555	–838	–3.7
Australia	428	354	74	20.9
China	3,755	3,691	64	1.7
India	695	666	29	4.4
Malaysia	753	770	–17	–2.2
Other	1,775	1,886	–111	–5.9
Asia–Pacific	7,406	7,367	39	0.5
Total world	**72,478**	**72,722**	**–244**	**–0.3**

*Angola became a member of OPEC beginning in 2007.
Source: Oil & Gas Journal.

OPEC oil production

Table 4

Country	First quarter 2007	First quarter 2006	Change	Change, %	OPEC quota, 1,000 b/d
	1,000 b/d				
Angola[1,3]	1,618	—	—	—	—
Algeria	1,330	1,360	–30	–2.2	810
Indonesia	850	923	–73	–7.9	1,396
Iran	3,903	3,847	56	1.5	3,861
Iraq[3]	1,893	1,717	176	10.3	—
Kuwait[2]	2,435	2,515	–80	–3.2	2,105
Libya	1,693	1,667	26	1.6	1,398
Nigeria	2,227	2,233	–6	–0.3	2,164
Qatar	797	820	–23	–2.8	676
Saudi Arabia[2]	8,475	9,332	–857	–9.2	8,561
United Arab Emirates	2,570	2,613	–43	–1.6	2,301
Venezuela	2,437	2,630	–193	–7.3	3,028
Total OPEC	**30,228**	**29,657**	**571**	**1.9**	**26,300**

[1]Angola became a member of OPEC beginning in 2007. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. [3]Not included in 2007 quota.
Source: Oil & Gas Journal.

Coal consumption will increase to 22.8 quads from 22.5 quads last year. Electric utilities and independent power producers are driving coal demand growth, as demand by residential users and coke plants is waning.

WORLD CRUDE PRICES[1]

Table 5

Country	Type of crude and API gravity°	June 1, 2007, $/bbl	% change 6–07/ 1–07	In effect Jan. 1, 2007, $/bbl	% change 07/06	In effect June 1, 2006, $/bbl	In effect June 1, 2005, $/bbl	In effect June 1, 2004, $/bbl	In effect June 1, 2003, $/bbl	In effect June 1, 2002, $/bbl
OPEC										
Saudi Arabia	Arabian Light 34	64.56	20.7	53.48	1.4	63.68	45.96	33.77	23.52	21.57
Abu Dhabi	Murban 39	70.15	14.3	61.39	0.5	69.77	52.67	37.53	26.69	24.98
Algeria	Saharan 44	70.82	18.5	59.77	1.1	70.07	50.07	37.73	27.17	22.92
Nigeria	Bonny Light 37	71.04	17.2	60.64	–0.6	71.48	51.61	37.87	27.44	23.32
Libya	Es Sider 37	67.18	18.2	56.83	–0.5	67.55	49.88	37.34	26.57	22.67
Indonesia	Minas 34	68.83	10.5	62.31	–1.5	69.85	50.81	38.06	28.24	24.51
Venezuela	Tia Juana 31	62.36	18.6	52.60	–3.6	64.71	47.69	36.92	27.81	23.18
Total OPEC		**65.88**	**19.7**	**55.06**	**1.2**	**65.11**	**47.29**	**35.09**	**25.04**	**22.47**
OTHER										
UK	Brent Blend 38	68.91	21.6	56.66	–0.7	69.43	51.21	37.78	27.58	23.26
Norway	Ekofisk 42	70.21	22.7	57.20	1.7	69.02	50.23	37.63	27.78	23.20
Mexico	Isthmus 33	62.25	18.6	52.49	–3.6	64.60	47.58	36.81	27.70	23.07
Russia	Urals 32	65.31	24.7	52.36	0.9	64.74	47.61	35.78	26.16	21.99
Total World		**65.37**	**19.7**	**54.63**	**1.1**	**64.67**	**46.65**	**35.29**	**25.72**	**22.31**
US[2]		62.10	20.4	51.57	–2.7	63.84	44.79	34.83	25.50	21.66

[1]Represents estimated contract prices based on government stated prices, netback deals and spot market quotations. [2]Average prices (f.o.b.) weighted by estimated import volume.
Source: US Energy Information Administration.

Nuclear energy net generation will climb 2.3% to a record high 8.4 quads this year. In the first quarter of 2007, the 104 operating nuclear units in the US ran at an average 94% of capacity, according to EIA. Nuclear energy will account for 8.3% of total US energy demand this year.

The total of all forms of renewable energy used will be 6 quads, down 3.3% from last year. Hydro demand is down due to below-normal precipitation in the northwestern US. Renewable energy sources, which include solar, hydro, wind, wood, and others, are mostly used by industrial and electric power customers.

In the first 3 months of 2007, conventional hydroelectric power consumption was down 11% from a year earlier. During the same period electricity generation from wind grew 18% but still totaled just 79 trillion btu for the quarter.

US CRUDE, PRODUCTS, AND NATURAL GAS PRICES

Table 6

Year	Average wellhead crude price, $/bbl	Refiner's acquisition cost of crude, $/bbl	Retail motor gasoline, all types, ¢/gal	Residential heating oil, ¢/gal	Average wellhead natural gas price, $/Mcf
1976	8.19	10.89	59.5	40.6	0.58
1977	8.57	11.96	63.1	46.0	0.79
1978	9.00	12.46	65.2	49.0	0.91
1979	12.64	17.72	88.2	70.4	1.18
1980	21.59	28.07	122.1	97.4	1.59
1981	31.77	35.24	135.3	119.4	1.98
1982	28.52	31.87	128.1	116.0	2.46
1983	26.19	28.99	122.5	107.8	2.59
1984	25.88	28.63	119.8	109.1	2.66
1985	24.09	26.75	119.6	105.3	2.51
1986	12.51	14.55	93.1	83.6	1.94
1987	15.40	17.90	95.7	80.3	1.67
1988	12.58	14.67	96.3	81.3	1.69
1989	15.86	17.97	106.0	90.0	1.69
1990	20.03	22.22	121.7	106.3	1.71
1991	16.54	19.06	119.6	101.9	1.64
1992	15.99	18.43	119.0	93.4	1.74
1993	14.25	16.41	117.3	91.1	2.04
1994	13.19	15.59	117.4	88.4	1.85
1995	14.62	17.23	120.5	86.7	1.55
1996	18.46	20.71	128.8	98.9	2.17
1997	17.23	19.04	129.1	98.4	2.32
1998	10.87	12.52	111.5	85.2	1.96
1999	15.56	17.51	122.1	87.6	2.19
2000	26.72	28.26	156.3	131.0	3.68
2001	21.84	22.95	153.1	125.0	4.00
2002	22.51	24.10	144.1	112.9	2.95
2003	27.56	28.53	163.8	135.5	4.88
2004	36.77	36.98	192.3	154.8	5.46
2005	50.28	50.24	233.8	205.0	7.33
2006	59.69	60.23	263.5	236.2	6.42
*2007	56.00	57.00	270.0	240.0	7.00

*OGJ estimate.
Source: US Energy Information Administration, for 1976-2006 data.

US gas market

Electric power and residential customers will push total gas demand to 22.49 tcf this year.

Gas is in greater demand as a result of more heating-degree days in the first 4 months of 2007 than during the same 2006 period and a summer that's expected to be warmer than normal. Also, experts at the National Oceanic and Atmospheric Administration Climate Prediction Center project a 75% chance that Atlantic hurricane activity will be above normal this year.

NOAA scientists predict 13-17 named storms, with 7-10 becoming hurricanes, of which 3-5 could become major hurricanes of category 3 strength or higher. With this level of activity, production from the Gulf of Mexico and along the Gulf Coast is at risk to sustain substantial disruptions.

Still, OGJ predicts that US gas

US ENERGY CONSUMPTION AND EFFICIENCY

Table 7

	GDP (billion 2000 dollars)	Energy consumption (trillion btu)	Energy consumption per GDP, 2000 dollar (Mbtu)	Oil energy consumption (trillion btu)	Oil energy consumption per GDP, 2000 dollar (Mbtu)	Natural gas energy consumption (trillion btu)	Total Natural gas energy consumption per GDP, 2000 dollar (Mbtu)	Total oil and natural gas energy consumption (trillion btu)	oil and gas energy consumption per GDP, 2000 dollar (Mbtu)	Oil and natural gas energy % of total energy
1973	4,341.5	75,708	17.4	34,840	8.0	22,512	5.2	57,352	13.2	75.8
1974	4,319.6	73,991	17.1	33,455	7.7	21,732	5.0	55,187	12.8	74.6
1975	4,311.2	71,999	16.7	32,731	7.6	19,948	4.6	52,679	12.2	73.2
1976	4,540.9	76,012	16.7	35,175	7.7	20,345	4.5	55,520	12.2	73.0
1977	4,750.5	78,000	16.4	37,122	7.8	19,931	4.2	57,053	12.0	73.1
1978	5,015.0	79,986	15.9	37,965	7.6	20,000	4.0	57,965	11.6	72.5
1979	5,173.4	80,903	15.6	37,123	7.2	20,666	4.0	57,789	11.2	71.4
1980	5,161.7	78,280	15.2	34,202	6.6	20,394	4.0	54,596	10.6	69.7
1981	5,291.7	76,335	14.4	31,931	6.0	19,928	3.8	51,859	9.8	67.9
1982	5,189.3	73,234	14.1	30,231	5.8	18,505	3.6	48,736	9.4	66.5
1983	5,423.8	73,066	13.5	30,054	5.5	17,357	3.2	47,411	8.7	64.9
1984	5,813.6	76,693	13.2	31,051	5.3	18,507	3.2	49,558	8.5	64.6
1985	6,053.7	76,580	12.7	30,922	5.1	17,834	2.9	48,756	8.1	63.7
1986	6,263.6	76,722	12.2	32,196	5.1	16,708	2.7	48,904	7.8	63.7
1987	6,475.1	79,156	12.2	32,865	5.1	17,744	2.7	50,609	7.8	63.9
1988	6,742.7	82,774	12.3	34,222	5.1	18,552	2.8	52,774	7.8	63.8
1989	6,981.4	84,886	12.2	34,211	4.9	19,712	2.8	53,923	7.7	63.5
1990	7,112.5	84,730	11.9	33,553	4.7	19,730	2.8	53,283	7.5	62.9
1991	7,100.5	84,522	11.9	32,845	4.6	20,149	2.8	52,994	7.5	62.7
1992	7,336.6	85,866	11.7	33,527	4.6	20,835	2.8	54,362	7.4	63.3
1993	7,532.7	87,579	11.6	33,841	4.5	21,351	2.8	55,192	7.3	63.0
1994	7,835.5	89,248	11.4	34,670	4.4	21,842	2.8	56,512	7.2	63.3
1995	8,031.7	91,200	11.4	34,553	4.3	22,784	2.8	57,337	7.1	62.9
1996	8,328.9	94,226	11.3	35,757	4.3	23,197	2.8	58,954	7.1	62.6
1997	8,703.5	94,790	10.9	36,266	4.2	23,328	2.7	59,594	6.8	62.9
1998	9,066.9	95,200	10.5	36,934	4.1	22,936	2.5	59,870	6.6	62.9
1999	9,470.3	96,827	10.2	37,960	4.0	23,010	2.4	60,970	6.4	63.0
2000	9,817.0	98,966	10.1	38,404	3.9	23,916	2.4	62,320	6.3	63.0
2001	9,890.7	96,304	9.7	38,333	3.9	22,861	2.3	61,194	6.2	63.5
2002	10,048.8	97,793	9.7	38,401	3.8	23,628	2.4	62,029	6.2	63.4
2003	10,301.0	98,103	9.5	39,074	3.8	22,967	2.2	62,041	6.0	63.2
2004	10,703.5	100,199	9.4	40,594	3.8	22,993	2.1	63,587	5.9	63.5
2005	11,048.6	100,505	9.1	40,735	3.7	22,886	2.1	63,621	5.8	63.3
2006	11,415.3	99,661	8.7	40,217	3.5	22,518	2.0	62,735	5.5	62.9
*2007	11,640.0	101,260	8.7	40,860	3.5	23,200	2.0	64,060	5.5	63.3

*Estimated.
Source: US Energy Information Administration.

US ENERGY DEMAND

Table 8

	2006 — Trillion btu	*2007 — Trillion btu	Change, %	% share of total energy 2006	% share of total energy *2007
Oil	40,217	40,860	1.6	40.4	40.4
Gas	22,518	23,200	3.0	22.6	22.9
Coal	22,511	22,800	1.3	22.6	22.5
Nuclear	8,208	8,400	2.3	8.2	8.3
Hydro, other	6,207	6,000	–3.3	6.2	5.9
Total	**99,661**	**101,260**	**1.6**	**100.0**	**100.0**

*OGJ estimate.
Source: 2005 US Energy Information Administration.

production will be little changed from last year, up 0.7% to 19.5 tcf. Production gains in Texas and some other states will outweigh declines of 5% in the federal Gulf of Mexico and 4.3% in Louisiana. US gas imports will increase to 4.21 tcf from last year's 4.19 tcf. LNG imports will surge, but pipeline imports of gas from Canada and Mexico will fall. The US will export 750 bcf of gas this year, up from 725 bcf in 2006.

The US will import 800 bcf of LNG this year, up 37%. High US gas prices relative to prices in Europe accelerated import growth in the first half.

The additional supply from LNG imports will help alleviate market tightness and high gas prices during the peak cooling months of 2007 and will provide insurance against lost production should hurricanes interrupt gas production in the gulf.

In March LNG imports rose to 86.83 bcf from 42.56 bcf the previous month and 33.16 bcf in March 2006, according to Waterborne Energy Inc.

The amount of working gas in storage will finish 2007 nearly the same as at the start, up 30 bcf. At the midyear point, gas inventories are near the top of the 5-year range, where they remained throughout the first 6 months.

US oil demand

Demand for oil products in the US this year will average 20.9 million b/d, up from 20.6 million b/d last year. Demand for transportation fuels and power generation are behind this growth.

US NATURAL GAS SUPPLY AND DEMAND

Table 9

	2004	2005	2006	Change, % 06/05	2007	Change, % 07/06
		bcf			bcf	
Production						
Texas	5,067	5,255	5,557	5.7	5,850	5.3
Louisiana	1,353	1,296	1,380	6.5	1,320	–4.3
Federal Gulf of Mexico	3,969	3,151	2,843	–9.8	2,700	–5.0
Other states	9,128	9,249	9,579	3.6	9,630	0.5
Total production	**19,517**	**18,951**	**19,359**	**2.2**	**19,500**	**0.7**
Imports						
Canada	3,607	3,700	3,591	–2.9	3,400	–5.3
Mexico	—	9	13	44.4	10	–23.1
LNG	652	631	584	–7.4	800	37.0
Total imports	**4,259**	**4,341**	**4,187**	**–3.5**	**4,210**	**0.5**
Supplemental gas	60	64	62	–3.1	64	3.2
Losses, etc.*	–479	–437	–618	41.4	–500	–19.1
Total new supply	**23,357**	**22,919**	**22,990**	**0.3**	**23,274**	**1.2**
Supply from storage	–114	51	–431	—	–30	—
Total supply	**23,243**	**22,970**	**22,559**	**–1.8**	**23,244**	**3.0**
Exports	854	729	725	–0.5	750	3.4
Total consumption	**22,389**	**22,241**	**21,834**	**–1.8**	**22,494**	**3.0**

*Extraction losses and unaccounted for gas
Source: 2004-2006 EIA; 2007 OGJ estimate.

In spite of strong pump prices, motor gasoline demand will increase to 9.35 million b/d from 9.23 million b/d last year. Last year demand grew 0.8% as the average pump price surged almost 13%. This year's higher pump prices and faster rising demand seem to indicate that drivers have adjusted to paying more for fuel.

The year's growth in jet fuel demand will be minimal, up 1% to 1.64 million b/d. Although passenger travel by air is up from a year ago, airlines are being more efficient as a result of high jet fuel prices.

Demand for distillate will be up 2.5% to average 4.275 million b/d this year as a result of greater use of diesel fuel. In the first 5 months of this year, demand climbed 2.6% from a year earlier, according to the most recent EIA data available.

Diesel fuel has been in greater demand since ethanol requirements for motor gasoline went into effect, because the oxygenate cannot be transported via pipeline to markets from plants predominantly located in the Midwest.

Residual fuel oil demand will increase to 780,000 b/d from 681,000 b/d last year. Resid demand fell 26% last year, primarily due to reduced demand at power plants that had the capability to switch to natural gas for fuel. OGJ forecasts that resid and gas prices will be nearer parity on a btu basis this year.

Use of LPG will average 2.1 million b/d this year, up 2.7%. In the first quarter of this year, production of LPG at gas processing plants and at refineries was up, and exports were down from the first quarter of 2006.

Demand for all other petroleum products this year will decline 2%. This group includes naphtha jet fuel, pentanes plus other hydrocarbons and oxygenates, unfinished oils, gasoline blending components, and all finished petroleum products except finished motor gasoline, distillate, resid, jet fuel, LPG, and crude oil that is used as fuel.

US oil supply

Total US liquids production this year will average 6.96 million b/d, up 1.3%.

Helping to boost supplies are a few major projects expected to begin production by yearend in the Gulf of Mexico. These include BHP's Thunder Hawk, BP's Atlantis, and Anadarko's Independence Hub.

Production of crude oil and condensate will average 5.2 million b/d, up from 5.14 million b/d. NGL and liquefied refinery gas production will climb 1.4% to 1.76 million b/d.

Through the first half of 2007, OGJ estimates that oil production was 5.177 million b/d, up 1.8% from the first half of last year. Onshore and offshore production was up slightly in Texas and up 10% in Louisiana.

Production was down in California, Colorado, and Montana for the first 6 months. And Alaskan output continued its slide, averaging 775,000 b/d vs. 798,000 b/d in the first 6 months of last year.

Imports

US oil imports will increase 1.1% this year. Imports of both crude and products will grow, averaging 13.76 million b/d.

FIRST HALF US CRUDE, CONDENSATE PRODUCTION

Table 10

	First half 2007*	First half 2006	Change, %
	1,000 b/d		
PAD District 1	21	22	–4.5
Florida	7	7	0.0
Others	14	15	–6.7
PAD District 2	458	452	1.3
Illinois	31	28	10.7
Kansas	95	96	–1.0
Michigan	14	15	–6.7
North Dakota	103	105	–1.9
Oklahoma	170	171	–0.6
Others	45	37	21.6
PAD District 3	2,919	2,780	5.0
Alabama	17	21	–19.0
Arkansas	15	17	–11.8
Louisiana	1,350	1,227	10.0
Mississippi	50	48	4.2
New Mexico	164	160	2.5
Texas	1,323	1,307	1.2
PAD District 4	328	345	–4.9
Colorado	52	62	–16.1
Montana	91	98	–7.1
Utah	44	48	–8.3
Wyoming	141	137	2.9
PAD District 5	1,451	1,485	–2.3
Alaska	775	798	–2.9
California	675	686	–1.6
Others	1	1	—
Total	**5,177**	**5,084**	**1.8**

*OGJ estimate.
Source: US Energy Information Administration.

OGJ forecasts that 2007 crude imports will average 10.2 million b/d, and imports of oil products will average 3.56 million b/d. The US resumed importing crude for the Strategic Petroleum Reserve in March, according to EIA. This is the first month of imports for the SPR since May 2006.

For the third straight year, Canada was the largest source of US imported crude oil in 2006, when the US received an average 1.782 million b/d from the country.

The second largest source for US crude imports last year was Mexico, followed by Saudi Arabia, Venezuela, and Nigeria.

US crude imports from OPEC member countries averaged 4.78 million b/d last year, up slightly from a year earlier. Oil product imports from OPEC countries averaged 719,000 b/d, down from 2005.

Canada also was the leading source of US product imports last year. The US

US REFINERY UTILIZATION

Table 11

	Crude runs	Input to distillation units	Operable capacity	Utilization rate,
	1,000 b/d			%
1986	12,716	12,817	15,467	82.9
1987	12,851	12,999	15,643	83.1
1988	13,246	13,447	15,927	84.4
1989	13,401	13,551	15,701	86.3
1990	13,409	13,610	15,623	87.1
1991	13,301	13,508	15,707	86.0
1992	13,411	13,600	15,460	87.9
1993	13,613	13,851	15,143	91.5
1994	13,866	14,032	15,150	92.6
1995	13,973	14,119	15,346	92.0
1996	14,195	14,337	15,239	94.1
1997	14,662	14,831	15,594	95.2
1998	14,889	15,108	15,802	95.6
1999	14,804	15,078	16,282	92.6
2000	15,067	15,296	16,525	92.6
2001	15,086	15,351	16,512	92.6
2002	14,947	15,180	16,700	90.7
2003	15,304	15,503	16,747	92.6
2004	15,517	15,781	16,982	93.0
2005	15,220	15,479	17,128	90.4
2006	15,240	15,598	17,400	89.7
*2007	15,510	15,780	17,500	90.2
1990-2007 change				
Volume	2,101	2,170	1,877	—
Percent	15.7	15.9	12.0	—
2006-07 change				
Volume	270	182	100	—
Percent	1.8	1.2	0.6	—

*OGJ estimate.
Source: US Energy Information Administration.

US OIL IMPORTS

Table 12

Sources of crude imports[1]

Country	Share of total 2007 %	First quarter average 2007, 1,000 b/d	Change 07/06, %	Annual average 2006, 1,000 b/d	Change 06/05, %	Annual average 2005, 1,000 b/d
Angola[2]	5.8	570	11.1	513	12.5	456
Indonesia	0.3	27	68.8	16	–15.8	19
Nigeria	11.7	1,156	10.8	1,043	–3.2	1,077
Saudi Arabia	13.4	1,325	–6.8	1,421	–1.7	1,445
Venezuela	10.4	1,033	–9.3	1,139	–8.2	1,241
Other OPEC	18.1	1,792	54.3	1,161	12.3	1,034
Total OPEC	**53.9**	**5,333**	**11.6**	**4,780**	**–0.7**	**4,816**
Canada	18.5	1,825	2.4	1,782	9.1	1,633
China	0.1	11	–42.1	19	–20.8	24
Colombia	1.1	107	–24.1	141	–9.6	156
Ecuador	2.2	214	–21.3	272	–1.4	276
Gabon	0.5	50	–16.7	60	–52.8	127
Mexico	14.9	1,475	–6.4	1,576	1.3	1,556
Norway	0.6	58	–40.8	98	–17.6	119
Trinidad and Tobago	0.5	52	–22.4	67	4.7	64
UK	0.9	90	–29.7	128	–42.9	224
Other non-OPEC	6.8	675	–42.4	1,172	3.6	1,131
Total imports	**100.0**	**9,890**	**–2.0**	**10,095**	**–0.3**	**10,126**

Sources of refined product imports

Algeria	6.2	208	–29.0	293	17.2	250
Saudi Arabia	0.5	18	–55.0	40	–56.5	92
Venezuela	7.2	244	–9.6	270	–6.3	288
Other OPEC	3.7	126	8.6	116	–17.7	141
Total OPEC	**17.7**	**596**	**–17.1**	**719**	**–6.7**	**771**
Canada	17.3	582	11.9	520	–5.1	548
Colombia	0.4	12	–7.7	13	–67.5	40
Italy	1.2	42	–26.3	57	32.6	43
Mexico	4.0	136	8.8	125	17.9	106
Netherlands Antilles	0.4	15	–54.5	33	13.8	29
Virgin Islands	10.8	363	11.3	326	–0.6	328
Other non-OPEC	48.2	1,627	–5.6	1,724	0.1	1,723
Total imports	**100.0**	**3,373**	**–4.1**	**3,517**	**–2.0**	**3,588**

[1]Includes imports for the Strategic Petroleum Reserve. [2]Angola became a member of OPEC beginning in 2007.
Source: US Energy Information Administration.

FIRST HALF US CRUDE AND PRODUCTS STOCKS

Table 13

	[1]2007, 1,000 bbl	Change 06/05, %	[1]2006, 1,000 bbl	Change 05/04, %	[1]2005, 1,000 bbl
Motor gasoline	201,500	–6.1	214,494	3.0	208,328
Jet fuel	42,000	6.8	39,313	–5.8	41,741
Distillate fuel oil	123,000	–5.3	129,878	–4.5	136,022
Residual fuel oil	35,500	–17.8	43,208	15.6	37,387
Unfinished oils	90,000	–1.2	91,101	6.3	85,723
Other	175,000	–6.7	187,526	4.1	180,155
Total products stocks	**667,000**	**–5.5**	**705,520**	**2.3**	**689,356**
Crude stocks[2]	343,000	2.0	336,245	3.9	323,704
Total	**1,010,000**	**–3.0**	**1,041,765**	**2.8**	**1,013,060**

[1]At end of June. [2]Excludes Strategic Petroleum Reserve.
Source: US Energy Information Administration, 2005-06. 2007, OGJ estimate.

imported an average of 521,000 b/d of products from Canada, a bit less than during the prior year. The next largest sources of products imported by the US last year were the US Virgin Islands, Algeria, Venezuela, and Russia.

Oil inventories

Crude and product inventories will finish this year nearly unchanged from the end of 2006. Crude stocks will be slightly lower at 310 million bbl, while product stocks will total 700 million bbl.

Crude stocks finished the first half of 2007 about 3% higher than at mid-2006. But inventories of most oil products were lower than a year earlier because of strong demand and refinery problems.

Half-way through this year, stocks of motor gasoline were down 5% from a year earlier. Inventories of resid were down 16%, and distillate stocks were 3% lower. At the same time, jet fuel stocks were about 2% higher than at the end of June 2006.

At the midpoint of this year, the amount of crude in the SPR was 690 million bbl, barely up from a year earlier. Since imports of crude for the reserve have resumed, OGJ forecasts that SPR stocks will be 700 million bbl at the end of this year. At the end of 2006, SPR stocks totaled 688.6 million bbl.

Refining

OGJ forecasts that this year's average US refinery utilization will be 90.2%, up from 89.7% last year. This assumes total inputs to refineries of 15.78 million b/d with operable capacity of 17.5 million b/d.

For the first 5 months of this year, US refinery utilization was 87.8%, roughly the same as a year earlier when some Gulf Coast refineries were struggling to resume normal operations following damage from the previous year's hurricanes.

US refinery activity in the first half of this year was hampered by numerous outages and unscheduled shutdowns for maintenance, which led to lower product inventories. At the same time demand for products was strong, up from a year earlier. Limited supply and strong demand pushed up product prices.

Refiners have had healthy cash margins for a couple of years.

The Gulf Coast cash refining margin

last year averaged $12.52/bbl, according to Muse, Stancil & Co. This compares with a 2005 average of $12.90/bbl. For the first 5 months of this year, that margin averaged $15.10/bbl, up 9.5% from the corresponding 2006 period.

But West Coast margins have been much higher than that, averaging $23.98/bbl for 2006 and $27.71/bbl for the first 5 months of this year. The monthly average for the West Coast margin peaked in May 2006 at $39.61/bbl.

There are still no firm plans to build a new refinery in the US, so operations will stay close to capacity rates unless demand slumps. Companies have weakening incentive to build capacity in light of calls for limits on the use of hydrocarbons and the rigorous permitting required for new facilities. ✦

US drilling growth slower as Canada faces large decline

Alan Petzet
Chief Editor-Exploration

Rising costs are slowing the recent rate of drilling growth in the US and savaging drilling in Canada.

Active rig counts in the first half of 2007 were 11% higher than the same period in 2006 in the US compared with full-year increases of 19% and 16% the previous two years, respectively.

Canada's rig count ran almost one third lower in January through June 2007 than in the first half of 2006.

Here are highlights of OGJ's midyear drilling forecast for 2007:

- Operators will drill 47,343 wells in the US, up from the 47,003 OGJ estimated in the early-year forecast (OGJ, Jan. 15, 2007, p. 31).
- Operators will drill 3,815 exploratory wells of all types, up from an estimated 3,550 last year.
- The Baker Hughes Inc. count of active US rotary rigs will average 1,780 rigs/week this year, up from 1,649 in 2006 and 1,383 in 2005.
- Operators will drill 19,164 wells in western Canada, down from an estimated 24,105 wells in 2006.

Drilling rates

Onshore gas plays seemed to be driving most of the gains in US drilling.

Arkansas, its Arkoma basin Mississippian Fayetteville shale gas play gaining momentum, averaged 41.9 rigs/week in the first half, 116% of the 2006 first half total (Table 1). The lead Fayetteville operator, Southwestern Energy Co., Houston, was running 19-20 rigs in the play, 15 of which are capable of drilling the curves and laterals of the horizontal wells.

With net acreage of 1,400 sq miles to evaluate and rigs still working 10 miles from each other in many areas,

HOW US, CANADA DRILLING COMPARE

Table 1

Average number of active rigs per week, year to date

	Jan. 1-June 23, 2006	Jan. 1-June 22, 2007
Alabama	4.6	3.9
Alaska	9.2	9.7
Arkansas	19.6	41.9
California	33.2	32.5
Land	28.7	30.7
Offshore	4.5	1.8
Colorado	85.2	101.7
Florida	0.5	0.3
Kansas	6.8	13.6
Kentucky	5.9	8.8
Louisiana	183.4	186.4
N. land	57.3	56.4
S. inland waters	19.3	24.0
S. land	35.6	38.6
Offshore	71.2	67.3
Michigan	1.8	1.4
Mississippi	6.9	16.8
Montana	23.4	19.8
Nebraska	0.0	0.0
Nevada	1.1	1.6
New Mexico	96.4	79.4
New York	4.5	7.1
North Dakota	28.3	33.1
Ohio	7.3	12.9
Oklahoma	170.4	181.8
Pennsylvania	15.6	14.5
South Dakota	0.9	1.5
Tennessee	0.0	3.8
Texas	710.0	818.2
Offshore	12.5	10.5
Inland waters	2.8	1.1
Dist. 1	20.3	21.5
Dist. 2	25.2	29.7
Dist. 3	62.9	56.1
Dist. 4	77.7	92.6
Dist. 5	126.9	162.4
Dist. 6	102.9	124.4
Dist. 7B	35.0	39.6
Dist. 7C	37.7	53.7
Dist. 8	80.1	108.0
Dist. 8A	29.3	26.1
Dist. 9	29.8	34.8
Dist. 10	66.9	57.6
Utah	35.4	42.5
Virginia	1.0	2.5
West Virginia	25.2	30.7
Wyoming	97.4	75.6
US total	**1,574.6**	**1,744.5**
US land	**1,462.8**	**1,639.2**
US offshore	**88.9**	**80.2**
Canada total	**476.7**	**336.7**

Source: Baker Hughes Inc.

INTERNATIONAL RIG COUNT

Table 2

Average number of active rigs per month, year to date

	Jan. 2006-May 2006	Jan. 2007-May 2007
WESTERN HEMISPHERE		
Argentina	77	86
Bolivia	4	3
Brazil	31	39
Chile	0	1
Colombia	21	30
Ecuador	12	11
Mexico	86	89
Peru	4	7
Trinidad	3	7
Venezuela	80	77
Other	1	2
Total Western Hemisphere*	**319**	**352**
ASIA-PACIFIC		
Australia	18	20
Brunei	3	4
China-offshore	16	18
India	81	84
Indonesia	51	51
Japan	2	2
Malaysia	15	16
Myanmar(Burma)	10	10
New Zealand	6	4
Papua New Guinea	3	3
Philippines	2	0
Taiwan	0	0
Thailand	10	11
Vietnam	10	7
Other	4	4
Total Asia-Pacific	**230**	**234**
AFRICA		
Algeria	22	25
Angola	4	5
Congo	1	3
Gabon	2	3
Kenya	0	0
Libya	9	12
Nigeria	9	7
South Africa	1	0
Tunisia	1	3
Other	3	6
Total Africa	52	64
MIDDLE EAST		
Abu Dhabi	14	13
Dubai	2	1
Egypt	33	42
Iran	NA	NA
Iraq	NA	NA
Jordan	1	1
Kuwait	12	13
Oman	35	45
Pakistan	15	19
Qatar	12	11
Saudi Arabia	57	76
Syria	22	22
Yemen	15	14
Other	2	1
Total Middle East	**220**	**258**
EUROPE		
Croatia	3	1
Denmark	4	3
France	1	1
Germany	3	5
Hungary	4	2
Italy	3	4
Netherlands	6	5
Norway	19	19
Poland	2	2
Romania	2	2
Turkey	4	5
United Kingdom	28	27
Other	4	5
Total Europe	**83**	**80**
Total World	**903**	**988**

*Excludes US and Canada
Source: Baker Hughes Inc.

Southwestern is probably no more than 50-60% along the learning curve with the Fayetteville shale that Mitchell Energy & Development Corp. climbed with the Barnett shale in the Fort Worth basin, Southwestern Chairman, Pres., and Chief Executive Officer Harold M. Korell said in June.

Barnett shale drilling helped in North and West Central Texas. North Texas Dist. 9 was up modestly at 35 rigs/week, while West Central Texas Dists. 7B and 7C combined for a 29% increase on the year to a total of 93 rigs. It is reported that 6,600 wells have been drilled in the Barnett shale play through mid-2007 since 1981.

Operators in East Texas Dists. 5 and 6, with the Bossier and numerous other vertical and horizontal plays going strong, fielded a combined 287 rigs/week, 46% more than in the first half of 2006.

Mississippi's first half average was nearly 17 rigs, almost three times the 2006 figure.

Oklahoma had a respectable 7.7% gain to 182 rigs/week.

Colorado averaged 102 active rigs in January through June, 18% more than in the same period a year earlier.

Utah averaged 42 active rigs in the first half, up 22% on the year.

North Dakota picked up rigs while Montana lost ground as the Bakken horizontal oil play moved east.

Wyoming averaged 76 rigs/week in the first half, down 22%. Other declines occurred in New Mexico and the Gulf of Mexico.

The international rig count excluding the US and Canada was about 9% higher at 903 rigs/month in the first half of 2007 compared with a year earlier. Most of the increase came in the Middle East and Latin America (Table 2).

Canada's status

Canada's outlook is bleaker as many producers became squeezed between several years of rising costs and lower natural gas prices.

Gas prices in Canada have largely recovered from weakness in 2006, but the fallout in lower drilling persisted well into the second quarter in the Western Canada basin.

Initial production at western Canadian gas wells is around 200 Mcfd, only one-fourth of what it was in the late 1990s. Unconventional gas wells are being drilled in great numbers, and their expected ultimate recovery is often greater than that of conventional wells, but they start out at low levels.

OGJ counted only four well bores drilled off Atlantic Canada in the first half of 2007, all of them off Newfoundland.

OIL & GAS JOURNAL WELL FORECAST FOR 2007

Table 3

State	First half 2007 Total wells	First half 2007 Exploratory wells	First half 2007 Field wells	Full year 2007 Total wells	Full year 2007 Exploratory wells	Full year 2007 Field wells	Full year 2007 Total footage (1,000)
Alabama	209	9	200	435	20	415	1,790
Alaska	76	2	74	157	5	152	1,116
Arizona	0	0	0	3	3	0	10
Arkansas	357	17	340	700	34	666	4,323
California land	1,273	33	1,240	2,550	66	2,484	6,862
California offshore	4	0	4	9	0	9	66
Colorado	1,574	76	1,498	3,350	161	3,189	20,284
Florida	0	0	0	1	1	0	13
Illinois	168	18	150	350	39	311	717
Indiana	62	5	57	130	11	119	200
Kansas	1,184	94	1,090	2,350	190	2,160	7,863
Kentucky	430	15	415	875	32	843	2,243
Louisiana	1,094	95	999	2,230	203	2,027	18,435
North	540	48	492	1,110	101	1,009	9,112
South	265	13	252	530	25	505	5,549
Offshore	289	34	255	590	77	513	6,284
Michigan	225	49	176	455	98	357	782
Mississippi	117	12	105	250	27	223	1,805
Montana	471	74	397	960	151	809	4,606
Nebraska	23	7	16	50	15	35	230
Nevada	2	2	0	3	2	1	15
New Mexico - East	623	39	584	1,230	76	1,154	8,840
New Mexico - West	462	6	456	950	10	940	4,486
New York	56	2	54	110	3	107	369
North Dakota	228	43	185	460	88	372	3,927
Ohio	441	48	393	875	102	773	3,489
Oklahoma	1,810	62	1,748	3,590	133	3,457	26,365
Oregon	6	6	0	10	10	0	28
Pennsylvania	1,490	146	1,344	2,975	292	2,683	11,207
South Dakota	6	1	5	14	2	12	134
Tennessee	89	9	80	175	17	158	393
Texas	7,105	623	6,482	14,160	1,273	12,887	111,878
Dist. 1	284	24	260	550	47	503	3,316
Dist. 2	350	49	301	685	103	582	5,449
Dist. 3	417	52	365	850	106	744	7,447
Dist. 4	655	58	597	1,340	118	1,222	12,761
Dist. 5	741	28	713	1,450	52	1,398	15,247
Dist. 6	825	83	742	1,675	184	1,491	16,765
Dist. 7-B	639	24	615	1,250	48	1,202	6,515
Dist. 7-C	696	37	659	1,410	75	1,335	10,646
Dist. 8	908	58	850	1,790	120	1,670	11,218
Dist. 8-A	474	49	425	965	99	866	5,533
Dist. 9	555	16	539	1,080	27	1,053	6,031
Dist. 10	503	122	381	995	241	754	9,880
Offshore	58	23	35	120	53	67	1,070
Utah	539	119	420	1,105	243	862	8,371
Virginia	244	39	205	475	76	399	1,434
Washington	3	3	0	6	6	0	84
West Virginia	948	144	804	1,925	293	1,632	8,097
Wyoming	2,294	64	2,230	4,425	133	4,292	17,811
US total	**23,613**	**1,862**	**21,751**	**47,343**	**3,815**	**43,528**	**280,781**
Western Canada	**9,447**	**2,684**	**6,759**	**19,164**	**5,450**	**13,704**	**76,093**
Alberta	7,112	2,134	4,978	14,528	4,358	10,170	57,676
Saskatchewan	1,740	348	1,392	3,454	691	2,763	12,003
British Columbia	420	168	252	835	334	501	5,211
Manitoba	170	34	136	335	67	268	1,151
NWT + Yukon Terr.	5	4	1	12	10	2	52
Eastern offshore	4	1	3	6	1	5	40
Eastern land	30	30	0	65	65	0	139

The Canada-Nova Scotia Petroleum Board, however, announced changes in April aimed at streamlining the licensing process and making the Scotian shelf a more attractive basin to explore (OGJ Online, Apr. 30, 2007).

The changes are designed to make more geological data available, keep companies from retaining blocks without exploring, and improve terms for new licenses. ✦

Lehman Bros.: 2007 E&P budgets boosted to $308 billion

Angel White
Associate Editor

Global exploration and production spending is expected to increase 13% to $308 billion, said Lehman Bros. Inc., New York. The amount is up from the 9% projected last December for 301 companies surveyed by the firm.

The increase is a result of expanding 2007 budgets by more than $12.6 billion, offset by overspending 2006 budgets by $1.1 billion, Lehman Bros. reported last month. The spending growth is driven by an upsurge in international investments (Table 1).

International spending is now estimated at 20% growth vs. the yearend estimate of 13%. "Operators have boosted their 2007 budget plans by $10.7 billion over the last 6 months, while underspending their 2006 budgets by $1.9 billion," said Lehman Bros. analysts.

Asian and European companies will make the largest additions to their 2007 capital expenditures, but growth is expected to continue broadly among all regions and company types.

Of the 87 companies surveyed in this category, national oil companies in Russia, Asia, and Latin America will continue to have the largest aggregate spending growth in 2007, the report said. Korea National Oil Corp. heads the list with its plans for hiking its spending by as much as 87%.

US spending

US capital expenditures for 2007 "were essentially unchanged from our December 2006 survey results," Lehman Bros. analysts said, adding, "[US] budgets are still expected to increase by 5% to $77.3 billion by the 274 companies we surveyed."

The report shows that the biggest gains are from the smaller companies (Table 2). "Companies spending less than $100 million indicate that 2007 spending levels will increase 15%," Lehman Bros. said. This amount, however, is down from the 31% increase these companies initially projected. The $100 million-$1 billion spenders, which include most of the publicly traded US independent E&P companies, boosted their 2007 spending plans to reflect a 10% surge, up from 7% last December.

Companies in this group posting the highest swells include St. Mary Land & Exploration, up 39%; Range Resources, up 32%; Ridgewood Energy, up 26%; and Statoil ASA, up 23%.

The supermajors, with budgets of more than $1 billion/year, expect to raise their 2007 E&P capital expenditures in the US by 1%. This amount is down two percentage points from the group's estimate at yearend 2006.

Canadian spending

Investments in Canada in 2007 are expected to decline by a bigger margin than was predicted last December, Lehman Bros. reported.

"While oil and gas companies modestly added to their expenditure plans for 2007 in Canada, these companies also overspent their 2006 budgets by $1.6 billion, which led to a bigger drop in capital expenditures year-over-year."

The Lehman Bros. survey results indicate that "Canadian E&P expenditures are anticipated to fall 11% in 2007 to an aggregate spending level of $24.6 billion by the 72 companies that we surveyed, as opposed to the 7.5% drop indicated in our yearend survey." The firm said it attempted to exclude oil sands spending from the survey.

The largest budget cuts are expected from the biggest companies (Table 3). Those companies that spend more than a $1 billion a year are now expected to reduce spending by 13% in 2007

OIL AND GAS EXPLORATION AND PRODUCTION SPENDING SUMMARY

Table 1

	2007 (estimated)	2006 (actual)	Year-to-year change, %	Companies surveyed	Year-to-year change in Dec. '06 survey, %	Companies surveyed
	Million $					
US	77,276	73,714	4.8	274	5.1	238
Canada	24,557	27,595	–11.0	72	–7.5	59
International	205,872	171,393	20.1	87	12.7	72
Worldwide	**307,705**	**272,702**	**12.8**	**350**	**8.9**	**301**

Source: Lehman Bros. Inc. from company data and estimates

US E&P EXPENDITURES BY COMPANY SPENDING LEVEL

Table 2

Spending level in 2006	2007 (estimated)	2006 (actual)	Year-to-year change, %	Companies surveyed
	Million $			
Less than $50 million	2,212	1,887	17.2	174
$50-100 million	1,539	1,377	11.8	20
Subtotal: less than $100 million	3,751	3,264	14.9	194
$100 million-1 billion	26,981	24,471	10.3	61
More than $1 billion	46,544	45,979	1.2	19
Total US spending	**77,276**	**73,714**	**4.8**	**274**

Source: Lehman Bros. Inc. from company data and estimates

CANADIAN E&P EXPENDITURES BY COMPANY SPENDING LEVEL

Table 3

Spending level in 2006	2007 (estimated) Million $	2006 (actual) Million $	Year-to-year change, %	Companies surveyed
Less than $50 million	321	420	–23.7	25
$50-100 million	738	618	19.3	8
Subtotal: less than $100 million	1,059	1,038	1.9	33
$100 million-1 billion	8,150	8,861	–8.0	30
More than $1 billion	15,349	17,695	–13.3	9
Total Canadian spending	**24,558**	**27,594**	**–11.0**	**72**

Source: Lehman Bros. Inc. from company data and estimates

from 2006 levels, and those that spend between $100 million and $1 billion a year will trim their budgets by 8%.

"The very smallest companies are expecting to modestly increase their spending by 2%, while these companies had expected flat to modestly down spending levels in 2007 previously," Lehman Bros. analysts said.

Listed among those companies that raised their 2007 expenditure forecasts are EOG Resources, up 39%; PetroCanada, up 20%; and Penn West Petroleum, up 14%.

The surveyed companies based their 2007 E&P budgets on commodity price assumptions of $56.90/bbl for crude and $6.74/Mcf for gas. This is up from the $55.14/bbl and $6.47/Mcf, respectively, used for their 2006 budgets. ✦

Congress approaches year's second half in punitive mood

Nick Snow
Washington Correspondent

The US oil and gas industry faces a Congress in a decidedly punitive mood as 2007's second half begins. Bills that initially aimed at repealing most of the 2005 Energy Policy Act's (EPACT's) incentives now contain additional provisions that would cost producers more money. Refiners are the targets of so-called price-gouging bills in both the House and Senate. And it's increasingly obvious that some federal lawmakers would like to use new oil and gas taxes to finance alternative energy research and development.

Senate Republicans blocked $29 billion in taxes that the Finance Committee tried to attach as an amendment to HR 6 on June 21. It would have repealed the manufacturing tax deduction for oil refiners, revised and reduced the foreign tax credit, extended and increased the oil spill liability tax, placed a 13% excise tax on future Gulf of Mexico production, and taxed finished gasoline at the refinery gate or as it was imported into the US.

"This tax package was a disaster and would have reduced supplies, leading to higher gas prices and more dependence on foreign oil," said Kay Bailey Hutchison (R-Tex.) following the vote. But Majority Leader Harry M. Reid (D-Nev.) said it would probably get a second look later this year.

The House Ways and Means Committee, meanwhile, approved its own package of oil and gas taxes in HR 2776 to finance alternative and renewable energy research and development by a 24-16 vote on June 20. It would raise more than $15 billion over 10 years by repealing the manufacturers' tax credit for refiners ($11.427 billion), revise and reduce the foreign tax credit by taxing both upstream and downstream income at the wellhead ($3.562 billion), and extend the geological and geophysical expense amortization period for large, integrated oil companies to 7 from 5 years ($103 million).

Other provisions

The bill also would, over 10 years, raise an estimated $85 million by making diesel fuel made from coprocessing biomass and petroleum ineligible for a $1/gal renewable diesel production credit and $109 million by limiting incentives for biodiesel, renewable diesel, and other fuel alternative production and consumption to the US. And in a move that House Democratic Caucus Chairman Rahm Emanuel of Illinois called "closing the Hummer loophole," HR 2776 would make large sport-utility vehicles ineligible for tax credits to raise $786 million.

The approximately $16 billion Ways and Means taxation and financing bill is a key element of an energy package Speaker Nancy Pelosi (D-Calif.) was expected to unveil on June 28 for action when the House returns from the week-long Independence Day recess in July. She previously said the package would contain incentives to expand renewable energy and efficiency programs, stronger support for production of domestically produced alternatives by US farmers, and more research and development of "the next generation of high-risk, high-reward energy technologies."

An energy bill was the last of six that Pelosi and the House passed in mid-January. HR 6 came to the floor on Jan. 18 under a rules suspension that precluded amendments and required a two-thirds majority for passage. The bill repealed $14 billion of oil and gas tax incentives for reinvestment in alternatives and conservation. It also contained a provision aimed at pressuring holders of Gulf of Mexico deepwater leases issued without price thresholds in 1998 and 1999 to renegotiate terms.

Once the bill was passed, Pelosi asked all the House committees with

jurisdiction to address energy independence by the Independence Day recess and climate change later in the year. She also formed a select committee on global warming and energy independence and made Edward J. Markey (D-Mass.) its chairman.

Separate actions

As committees and subcommittees held hearings through the winter and spring, two committees sent bills to the House floor that were approved with two-thirds majorities under suspended rules.

The Judiciary Committee's HR 2264, which aims to make foreign oil cartels subject to US antitrust laws, passed on May 22. The Energy and Natural Resources Committee's HR 1252, which would make oil and gas price-gouging a federal crime during a national energy emergency declared by the president, passed on May 23. The Senate added versions of both bills as part of its main amendment to HR 6 on June 21. Both would likely be vetoed by President George W. Bush.

The most significant portion of Pelosi's energy legislation package for oil and gas producers probably will come from HR 2337, which passed the House Natural Resources Committee on June 13. It would repeal EPACT provisions suspending onshore drilling permit processing fees and initiating a process which could lead to federal oil shale leasing and development. Committee members persuaded Chairman Nick J. Rahall to extend an EPACT requirement for the US Bureau of Land Management to meet a deadline for processing onshore drilling permit applications to 90 from 30 days instead of eliminating it.

At a May 23 hearing on the bill, Rahall's strongest criticism was of the US Minerals Management Service's crude oil royalty-in-kind program, which the Department of the Interior agency says has improved efficiency and reduced expenses but which the lawmaker says is plagued with scandal. An MMS spokesman later confirmed that the US Department of Justice is investigating two possible ethics violations in the RIK program following a probe by DOI's inspector general and that the program's director, Gregory Smith, would retire effective May 26.

HR 2337 would limit royalties-in-kind to oil for the US Strategic Petroleum Reserve. The bill also would impose new requirements for handling produced water and increase rights of surface landholders in split-estate situations involving federal leases. Rahall maintained that it simply tries to correct federal energy policy flaws. Committee Republicans said it does nothing to increase domestic production while imposing more restrictions.

Oil companies' 'gluttony'

Rising gasoline prices through the spring obviously affected congressional energy attitudes. When Senate Democrats announced on May 23 that they would bring several of their own proposals to the floor when debate began on HR 6, 3 weeks later, Reid said: "We think anything we do should have some effect on the gluttony of the oil companies. The mere fact that we're talking about legislation should get their attention."

But differences beyond oil and gas emerged as the Senate debated the Reid amendments to HR 6 for 2 weeks in June. Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) was stymied in his effort to make a renewable portfolio standard part of the bill, largely because the committee's chief minority member, Pete V. Domenici (R-NM), and other Republicans wanted to include clean coal technologies.

Domenici was more successful on June 21, when he convinced the Appropriations Committee to drop an amendment it had accepted a day earlier by Interior and Environment Appropriations Subcommittee Chairwoman Dianne Feinstein (D-Calif.) to bar holders of deepwater GOM leases issued in 1998-99 without price thresholds from future lease sales if they did not renegotiate terms.

Relations between Bingaman and Domenici are cordial in comparison to those of Environment and Public Works Committee Chairwoman Barbara Boxer (D-Calif.) and her predecessor under the Republicans, James M. Inhofe (Okla.). When he proposed an amendment to include clean-coal technology in refinery-siting legislation, she called it "a total taxpayer giveaway to the oil industry [that] short-cuts many environmental safeguards which protect our families."

Rep. Joe Barton (R-Tex.), the House Energy and Commerce Committee's chief minority member, exemplified congressional Republicans' frustration over the Democrats' energy issues approach during 2007's first half in his June 27 opening statement as the committee met to mark up bills. "Isn't it ironic that our most abundant domestic energy resource, coal, is not germane; that our cleanest energy resource, nuclear energy, is not germane; that our most used energy resources, oil and gas, are not germane; that the system of refining those products, unless we draft refining amendments in such a way that biofuels are the principal reason for the amendment, are not germane?" he asked. ✦

EPA proposes reduction in national ozone limits

Nick Snow
Washington Correspondent

The US Environmental Protection Agency has proposed the first reduction in the national ambient air quality standard (NAAQS) for ground-level ozone since 1997.

EPA said its proposal is based on recent scientific evidence about the health effects of ozone.

EPA said ground-level ozone levels have dropped 21% since 1980 as state and local governments have cooperated

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

The Russian energy view

Russia indisputably is a growing force in world energy. That's why it's good to periodically hear the perspectives of actual Russians.

Two of them discussed "Russia, the European Union and China: The State of the Energy Security Debate" at a June 21 Washington forum sponsored by the US Department of State's Bureau of Educational and Cultural Affairs. The event took place about a mile from where the US Senate was debating an energy bill aimed at reducing reliance on imported oil and increasing development of renewable and alternative sources.

The Russians were interested in diversification, too. Their country's location between China and Europe makes it only natural for them to want to export oil and gas into more than one market, observed Maria Belova of the Institute for Energy and Finance in Moscow. "This involves not only security of supplies, but security of demand," she said.

Shipments to the east ultimately could go beyond China. "We negotiate with all Asia-Pacific countries and try to choose the best option. China has growing demand but may not be willing to pay the best price. Negotiating with Japan and Korea may show China we have other choices," she said.

Investment restrictions

"Russia's energy exports are growing, and the name of the game is diversification," maintained Vitaly Merkushev, director and cofounder of the Eurasian Political Studies Network in Moscow. Criticism of investment restrictions can run in more than one direction, he suggested.

Despite the presence of Lukoil retailers in some US cities, Russian oil has not significantly penetrated the US market because of perceived limits on export capacity and a belief that Russian crude is such low quality that it requires special refining equipment, he said.

"Russia will never sign the European Energy Charter and Transit Protocol because it will never privatize Gazprom," the state-owned natural gas giant, Merkushev predicted. There is room to negotiate transportation and foreign investment upstream, he said, "But please give us a chance to invest downstream in markets outside our own country."

1990s experience

Both Russians said their country has learned a lot from its initial exposure to outside investment during the 1990s. "Sakhalin lost 28% of its population during that period because the foreign partners hired Canadians and Americans instead of local people," Merkushev said.

"We need experience and technology more than foreign investments," added Belova, who noted that Russia's production growth has come from Soviet era properties. "Contractors have tried to sell us adequate, rather than the best, technology. We need more common rules for technology exchanges, not bilateral agreements."

Finally, said both Russians, while their country is interested in the benefits substantial energy exports would bring, it also wants to make certain that its own industries and agriculture grow. "Russia is not a petro-economy. It's much more diversified," Merkushev said. ✦

to reduce emissions of ozone precursors, mainly nitrogen oxides and volatile organic compounds.

It proposes to lower the 8-hr primary ozone standard, which is designed to protect human health, to 0.07-0.075 ppm from 0.8 ppm. EPA also is taking comments on alternative standards from 0.06 ppm to the current 0.08 ppm, 8-hr standard.

The secondary standard, aimed at protecting trees, plants, and crops, would become lower to protect vegetation during growing seasons or remain identical to the primary standard. "New scientific evidence since the last review shows that repeated exposure to low levels of ozone damages vegetation, leading to increased susceptibility to disease, damaged foliage, and reduced crop yields," EPA said in a fact sheet issued with the proposal.

Industry reactions

Oil industry groups warned that reducing the ozone NAAQS is unnecessary and could limit growth in domestic refining capacity. "The current standard is working," the American Petroleum Institute said in a statement. "Emissions from cars and trucks as well as from power plants are being significantly reduced and the air is getting cleaner as a result. Even more progress will be made over the next 2 decades, due to control programs that are already in place."

Charles T. Drevna, executive vice-president of the National Petrochemical & Refiners Association, said EPA itself has noted that emissions contributing to the six pollutants with statutory standards dropped 54% from 1970 to 2006 as the US economy grew dramatically, and national average ground-level ozone levels have fallen 21% since 1980.

"Since the states have not yet fully implemented the current standard, EPA should instead help localities implement the current standard before imposing a brand new one that could

result in further negative impacts on American businesses as they attempt to compete in a global marketplace," Drevna said.

EPA said it is estimating the health benefits of meeting a range of alternative ozone standards based on published scientific standards and the opinion of outside experts. It expects to detail these findings in a regulatory impact analysis, which will include both the estimated costs and benefits, in the next few weeks.

The agency said it would take public comments for 90 days following publication of its proposal in the Federal Register. It also plans to hold four public hearings on Aug. 30 in Los Angeles and Philadelphia and on Sept. 5 in Chicago and Houston. ✦

IEA reports industrial energy efficiency analysis

Changes to manufacturing technology worldwide could cut energy use 18-26% and also reduce carbon dioxide emissions, the International Energy Agency said in a report released June 25 in Paris.

IEA Director Claude Mandil said, "Manufacturing industries in [Organization for Economic Cooperation and Development] countries have made great progress in energy efficiency during the last 25 years, but important opportunities to reduce emissions remain." His comments came as he released a report entitled "Tracking Industry Energy Efficiency and CO_2 Emissions."

In 2005, the Group of Eight (G8) leaders asked IEA to provide advice on a clean, competitive energy future. The report analyzed industrial energy efficiency.

The report said the manufacturing industry accounts for 36% of world CO_2 emissions. CO_2 is a greenhouse gas blamed for contributing to global warming.

IEA analysts used 27 gigatonnes/year of CO_2 emissions as a reference for their calculations. That was based upon 2004 statistics. They said industrial CO_2 emissions reduction potential amounts to 1.9-3.2 gigatonnes/year.

Among other industries, IEA studied chemicals and petrochemicals, iron and steel, cement, aluminum, pulp and paper.

The chemical and petrochemical industry accounts for 30% of global industrial energy use and 16% of CO_2 emissions, the report said.

Benchmarking studies suggest potential energy efficiency improvements for olefins and aromatics range from 10% for polyvinyl chloride to 40% for various types of polypropylene, IEA said.

The report said manufacturing in general could be made more energy-efficient by upgrading factory engines, including adjustable speed drives, steam systems, and combined heat and power, and also by recycling materials.

IEA noted that energy efficiencies differ widely between countries. China accounted for 80% of the growth in industrial production and CO_2 emissions during the past 25 years, the agency said. Mandil said improving industrial energy efficiency can help developing countries' economic growth while contributing to reduced greenhouse-gas emissions.

"The potential is so large that more efforts are warranted, in order to achieve deep CO_2 emission reductions, reduce fossil fuel dependence, and increase industrial competitiveness," Mandil said. The report concluded that more work needs to be done to improve the quality of the data and to refine the analysis, he said. ✦

IEA urges Germany to reconsider nuclear strategy

Uchenna Izundu
International Editor

Germany is in danger of increasing carbon emissions because of a proposal to shut down its nuclear power plants within the next 15 years, the International Energy Agency warned in a review of the country's energy policy.

Germany's energy policy is of critical importance within Europe and worldwide as it is the third largest economy among IEA members and is one of the largest energy markets in Europe.

IEA urged Germany to reconsider the policy because the country would be forced to rely on fossil fuels to plug its looming energy supply gap if it drops nuclear power as part of its energy mix. Nuclear power provides 12% of German's energy and a quarter of its electricity generation. "Losing the nuclear option will have significant impacts on energy security, economic efficiency, and environmental sustainability," IEA said. It would also reduce supply diversity and increase reliance on energy imports, "particularly natural gas, which is not diversified enough."

Russia is the main gas supplier to Germany, but there are fears among European nations about the reliability of Russian deliveries, and the growing focus on cutting carbon emissions have positioned nuclear power as an attractive option in the energy mix.

In addition, Germany's electricity and natural gas markets are dominated by large incumbent players, with E.ON

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Khodorkovsky's 44th birthday

Supporters of former OAO Yukos Chief Executive Mikhail Khodorkovsky gathered in Moscow last week to celebrate his 44th birthday, and reports say that things went well enough.

Local radio station Echo Moskvy reported that 40 people gathered at Gogolevsky Boulevard on June 26 to wish Khodorkovsky good health and patience, after which they uncorked bottles of sparkling wine.

Notably, Echo Moskvy said the celebration passed without intervention by the police. If that sounds a bit odd, consider similar celebrations held in Chita, the Siberian town where Khordorkovsky is imprisoned.

Representatives of a company that produces and organizes fireworks were detained in Chita on June 26 for organizing a fireworks display to celebrate Khodorkovsky's birthday.

Fireworks in Chita

A pyrotechnician and a driver who work for the company were brought to the Ingoda District Interior Department, along with a cameraman from a television company.

Later the same day, the organizer of the event, deputy chairman of the Chita public committee, which campaigns for Khodorkovsky's release, also was taken into custody.

The official, Marina Savvateyeva, said she was brought to the police station by police officers from the Ingoda District Interior Department in Chita.

The Chita regional police denied that Savvateyeva had been detained, saying, "She was invited to the police department to provide explanations." Invited? Hmmmm. That's a good one. Were they having a party, too?

Savvateyeva was released later in the day, apparently after giving no explanations.

"Based on Article 51 of the Russian Constitution, I refused to give any explanations regarding the organization of a salute in honor of Khodorkovsky's birthday," Savvateyeva said.

"As far as I know, the two employees of the firework company who were detained on Tuesday morning are still at the Ingoda District Interior Department," she said.

PWC under pressure

The cameraman and the employees of the fireworks company were eventually released after—as Savvateyeva put it—"the company's manager presented a license to run this business."

Speaking of business, Khordorkovsky's defense team does not think the decision by PriceWaterhouseCooper to revoke Yukos's audit reports for 1995-2004 will have any adverse effect on the new criminal case against their client.

"I do not think that this decision will have a negative effect," said Khodorkovsky's lawyer, Yuri Schmidt. "It is hard to draw any conclusions because the case is contradictory: On one hand, they claim that the money was stolen, but, on the other hand, they are claiming back taxes. What back taxes are they talking about if the money was stolen?"

PWC's sudden about-face on Yukos comes after months of government pressure in which the firm's Moscow office was subjected to a police raid and document seizures in March and the threat of having its license to operate in Russia revoked.

A PWC official said the withdrawal of the audits had nothing to do with the pressure on the firm. ✦

and Wingas together supplying 66% of the gas market and E.On AG, RWE, EnBW, and Vattenfall owning 70% of Germany's electricity capacity.

IEA said current legal unbundling rules are insufficient to address cross-ownership that could lead to large incumbents abusing their position and stifling competition. However Germany took an important reform step when it installed an energy market regulator, the Bundesnetzagentur, in 2005, and the country has made other important improvements over the past 5 years.

IEA recommended that the government introduce separate independent system operators to manage transportation assets so all markets are on an equal footing and to drive competition.

Although Germany is keen to address climate change within its energy policy, IEA urged that Germany rethink how it uses the European Union's emissions trading scheme to protect and promote coal-fired power generation. "The feed-in tariffs provided to renewable electricity generation sources do not provide long-term signals to lower costs—incentives that would allow more renewables to be procured from the same pot of funds," it said. ✦

Oil worker killed, five wounded in Yemeni attack

Eric Watkins
Senior Correspondent

One oil worker was killed and five wounded on June 23 when a Yemeni guard opened fire on a group of workers at an Occidental Petroleum Corp. site in Yemen's Shabwa province, about 300 miles south of the capital of Sanaa.

The victims were disembarking an airplane that had landed at Oxy's Al-Naeem airstrip in Shabwa when the guard randomly opened fire at them, according to a report in the Al-Ayyam newspaper.

Yemen's Interior Ministry said a

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female Indian oil engineer died in the attack, while Oxy said only that one of its subcontractors, a non-American, was killed. A local governor claimed the Yemeni guard was mentally ill—a phrase often used by officials when terrorists are involved in violence.

The shooting came just days after an earlier attack in nearby Aden. On June 19, Yemeni security officials said they arrested two men, suspected of being linked to al-Qaeda, who confessed to the attempted bombing of an oil pipeline in the southern province.

The attacks come amid renewed warnings of violence against Westerners in the country, particularly on the oil sector.

On June 21, a terrorist web site posted an undated audio statement from the leader of the so-called "Al-Qaeda of Jihad Organization in the Land of Yemen."

A speaker on the audio said the Yemeni group would not negotiate with the government and that the group will "continue jihad until the last Crusader is driven out of the Arabian Peninsula."

Last November, the same web site posted the first statement from the group, in which it claimed responsibility for attacks on oil facilities in Hadramaut, Yemen.

Terrorists have long sought to disrupt Yemen's oil developments.

In October 2002, the French Foreign Affairs ministry confirmed that the "initial results" of the investigation being conducted by French, Yemeni, and American investigators aboard the tanker Limburg indicate a terrorist attack (OGJ Online, Oct. 11, 2002). Al-Qaeda later claimed responsibility for the attack in which one seaman aboard the Limburg was killed. ✦

More oil firms join Statoil's Mongstad carbon test center

Paula Dittrick
Senior Staff Writer

DONG Energy, Hydro ASA, and Royal Dutch Shell PLC agreed to cooperate with Statoil ASA in planning a carbon capture and storage (CCS) test center at a combined heat and power station (CHP) being constructed at Statoil's 200,000 b/cd Mongstad refinery. Electric power company Vattenfall AB of Sweden also signed the CCS agreement.

The CCS test center, which will have an initial capacity of capturing 100,000 tonnes/year of carbon dioxide, is to be in place when the CHP plant starts operating in 2010. The center will be run by a technology company consisting of a partnership of Statoil, the Norwegian government, and the newly announced partners. Statoil will own 20% of the center, to be called the European CO_2 Test Centre Mongstad.

Norway, Statoil ASA, and four other partners are planning a carbon capture and storage test center, yet to be constructed at Statoil's 200,000 b/cd Mongstad refinery. The European CO_2 Test Centre Mongstad is slated for start-up in 2010. Photo by Harald M. Valderhaug for Statoil.

A 2006 agreement between the Norwegian government and Statoil outlines plans to develop an "environment-friendly" power project at Mongstad. The CHP station is expected to supply 280 Mw of electricity and 250 Mw of heat. The refinery will use some of the heat and electricity with the surplus electricity probably to be sold to Norwegian oil and gas operations, including Norwegian North Sea platforms.

The Norwegian Ministry of the Environment issued an emissions permit stipulating that a full-scale CCS project must proceed in parallel development with the CHP station. The full-scale CCS project, scheduled to be in place by Dec. 31, 2014, involves only the Statoil and the government, at least at this point.

The center will be capable of testing more than one type of CO_2 capture technology. Planners will spend the next several months selecting a detailed concept for additional preengineering and executing front-end engineering design contracts. Project sanction is expected in first quarter 2008. The Norwegian Ministry of Petroleum and Energy would like the planning partners

to participate in the test center after project sanction, although they have yet to make that commitment, a ministry spokesman said.

Statoil's carbon strategy

Statoil said the test center will develop, test, and qualify carbon capture technology to help reduce costs and risks associated with large-scale carbon capture. The company's intention is to develop technology capable of capturing more than 2 million tonnes/year of CO_2 at Mongstad. Both Statoil and the Norwegian government intend for technology and expertise acquired there to be available for international application.

In a related development, Statoil signed a joint development contract with technology development company Alstom to test chilled ammonia capture of CO_2 from flue gases particular to natural gas combined-cycle power plants. The objective is to construct a chilled ammonia test plant, and Statoil intends to include this in the work at the Mongstad test center.

Statoil and Alstom have collaborated on chilled ammonia capture since 2005, and the joint development contract is a step toward commercialization, Statoil said. Research indicates chilled ammonia-based CO_2 capture can remove as much as 90% of CO_2 from flue gases, Alstom said.

"We have chosen to work in parallel with one technology with great potential, chilled ammonia, which is less mature and therefore represents a higher risk," said Dag Vareide, Statoil's vice-president for research and technology. In parallel, Statoil plans to advance CO_2-removal amine technology.

"We have more experience with amine technology, and its use includes carbon capture at Sleipner, Snohvit, and In Salah," Vareide said.

At Sleipner natural gas field in the Norwegian North Sea, CO_2 content is about 10%. The CO_2 has been extracted from the gas flow since 1996 at the rate of 1 million tpy and reinjected into a nonpetroleum reservoir at 1,200 m overlying the field reservoir, which lies at 3,000 m subsea. The aim is to gather data to develop sound methodologies for assessment, planning, and long-term monitoring of underground CO_2 storage on and offshore.

Snøhvit gas field in the Norwegian Barents Sea has a high CO_2 content. The development includes piping the field gas to an onshore facility. CO_2 will be extracted from the gas stream and piped back offshore for injection into a sand aquifer underneath the gas field. The methane will be converted to LNG at the onshore facilities.

In Algeria, Statoil in involved with CO_2 sequestration at the In Salah project, which involves a group of gas fields and a massive processing complex. BP PLC is the project operator. ✦

Magnitude of undiscovered resource in Iraq's western desert in dispute

Sadad Al-Husseini
Saudi Aramco (retired)
Dhahran

Moujahed Al-Husseini
GeoArabia
Manama, Bahrain

The issue of accuracy in reporting oil and gas reserves and resources in the Middle East gulf region has been a cause for professional concern inside and outside the region for many decades.[1] Hundreds of billions of barrels of oil reserves are reported as proven and undiminished, year-after-year, even though little technical data are available to confirm the reliability of these estimates.

While some producers such as Iraq and Iran have not conducted significant exploration and development programs for years to justify their current reserves, others such as Kuwait have reported conflicting proved reserves that fluctuated from 48 billion bbl to 100 billion bbl.[2]

To further compound these issues, unsubstantiated reports have frequently appeared in the general media that further obfuscate the accurate oil and gas resource estimates for this region. For example, on Apr. 18, 2007, the energy consultancy IHS Inc. issued a press release that stated that up to 100 billion bbl of oil resources remain to be discovered in the western desert of Iraq (www.ihs.com). Within days, this release was quoted on the front-page of London's Financial Times followed by many other newspapers and magazines (for example: Dubai's Gulf News, Apr. 23; Time magazine, Apr. 24; Cyprus' MEES, Apr. 30).

Technical questions

Taking this report on its own merits, it immediately raises fundamental technical questions regarding its credibility.

First there is the reality that this conclusion stands in stark contrast to the 2004 study by the US Geological Survey (USGS) and GeoDesign, a consultancy that specializes in Iraq's petroleum geology. The latter study estimated the undiscovered oil resources of Iraq's western desert to total only half a billion barrels at the 95% level of probability and 1.6 billion bbl at the 50% level of probability.[3]

The USGS-GeoDesign study used a modern geological-statistical basin model that combined all the then-available data and knowledge regarding the petroleum reservoirs, source rocks, migration routes, and structural traps of Iraq. It considered 526 known prospects and fields, of which 370 remained undrilled, to estimate the potential number and sizes of undiscovered fields (Fig. 1).

The IHS press release stated that its own study had evaluated a comparable number of 516 known structures, of which 435 were undrilled prospects or noncommercial discoveries. From these statistics, we can conclude that both studies worked with essentially the same databases.

The USGS-GeoDesign study concluded that all the undiscovered crude oil resources of Iraq, including the western desert, may only total 13.2 billion bbl at the 95% level of probability and 45.1 billion bbl at the 50% level of probability. Even under the most optimistic circumstances at the 5% level of probability, USGS-GeoDesign did not consider the entire Iraqi undiscovered resources to exceed 84.1 billion bbl. These total estimates fall far short of the IHS conclusions for just the western desert of Iraq.

Petroleum systems

Beyond the USGS study, the conclusions of the IHS report are paradoxical because the potential petroleum resources of Iraq's western desert are relatively easy to estimate.

For example, it is well-established from existing wells and seismic data that the prospective formations in western Iraq are mostly of Paleozoic age and are characterized by a complex lateral stratigraphy.[4-9] This is confirmed by the reservoirs in Akkas field, the only commercial oil and gas-condensate field in

Iraq's western desert.

The analog to Akkas field is Jordan's Paleozoic Risha field located along the Iraqi-Jordanian border. Risha field produces 30 MMcfd of gas from more than 30 wells. It extends across a vast area (10 by 50 km), but the reservoir is a thin sheet of complex sandstones in faulted glacio-fluvial channels, ranging in thickness from 2 to 12 m. Its proven reserves are 180 bcf of gas, the equivalent of only 32.4 million bbl of oil.

Besides Jordan and Iraq, this Paleozoic petroleum system has also been evaluated in eastern Syria and northwest Saudi Arabia by both seismic surveys and wildcat drilling. In Saudi Arabia, these efforts identified numerous exploratory prospects of considerable acreage and vertical closure comparable to other features throughout the gulf region. The oil and gas sourcing and reservoir preservation in these prospects, however, was disappointing. Only one small gas field was discovered near the northern Saudi Arabian city of Tabuk.

In contrast to these efforts, other exploration activities in Saudi Arabia and adjacent Middle East gulf countries have discovered numerous Paleozoic oil and gas fields, including the Khuff gas reservoirs, and the pre-Khuff Unayzah and Al Jawf reservoirs in Saudi Arabia.

Based on these extensive regional efforts and exploration results, the indications are clear that this vast region (extending from northwest Saudi Arabia through eastern Jordan and Syria, and western Iraq) is not very prospective for oil. In fact, to discover 100 billion bbl of crude oil in the western desert of Iraq, as suggested by the IHS report, would require discovering and delineating the equivalent of 3,000 Risha-sized oil fields. Clearly if this was a realistic possibility, many similar prospects would have been drilled and oil or gas discovered decades ago in Syria, Jordan, and northwestern Saudi Arabia.

Estimation process

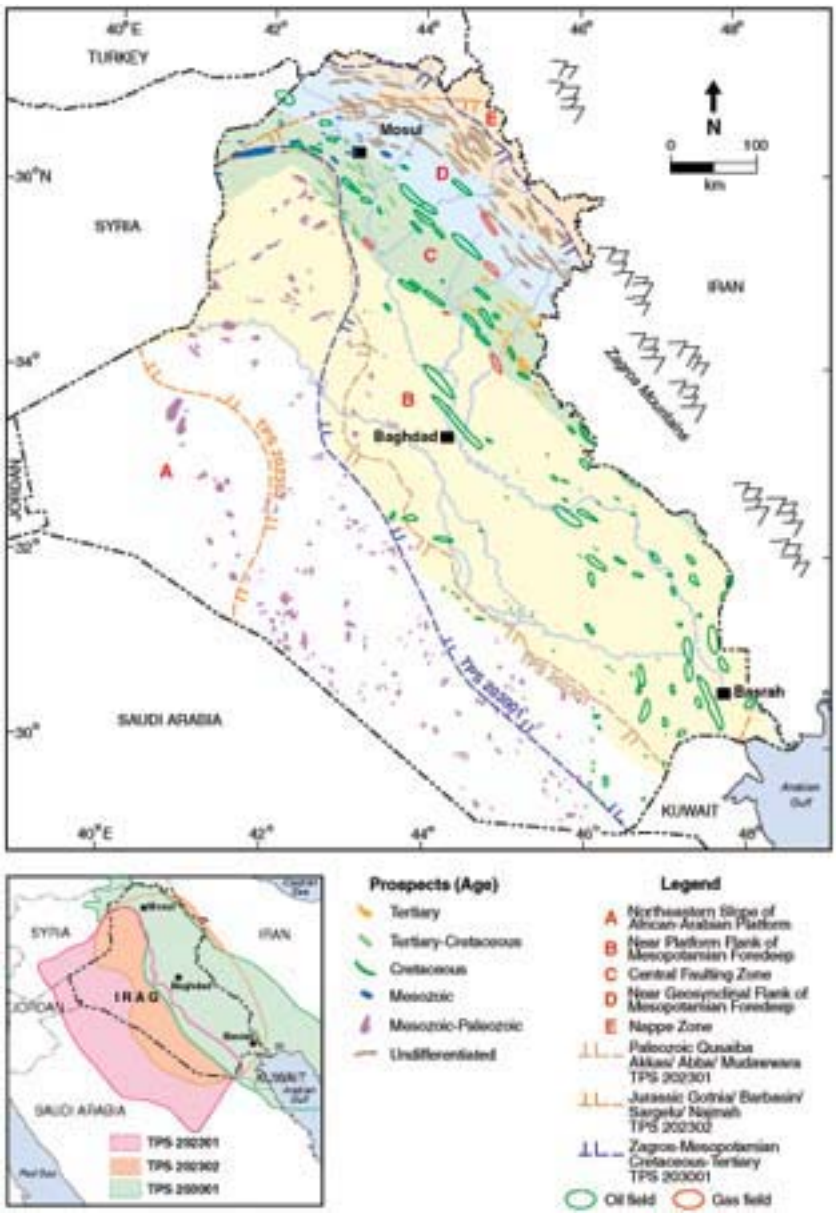
Perhaps the most important conclusion to be drawn from these profoundly contradictory studies is the need for a higher level of discipline and objectivity in the process of estimating global oil reserves and resources.

After all, the difference between the two studies in this one region represents nearly 100 billion bbl of oil resources. This in turn is the equivalent of 10% of the entire world's reported proven oil reserves.

While arriving at identical conclusions from such studies for one geological region is not realistic, discrepancies in technical estimates that differ by two orders of magnitude must surely

IRAQ'S THREE PETROLEUM SYSTEMS

Fig. 1



Source: Total petroleum systems identified by the US Geological Survey that have contributed to the petroleum accumulation in Iraq, after Ahlbrandt et al., 2005. Oil and gas fields and prospects after Al-Gailani, 2003, and Verma, et al., 2004, reproduced by permission from GeoArabia.

indicate a major flaw in the resource estimation process. ✦

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The authors

Sadad Al-Husseini, formerly Saudi Aramco's executive vice-president for exploration and producing, retired from the company on Mar. 1, 2004. He joined Saudi Aramco in 1972 and was the senior executive for exploration and development from 1986 through 2002. He has a BSc in geology American University of Beirut and an MSc and PhD in earth sciences from Brown University.

Moujahed Al-Husseini has been editor-in-chief of GeoArabia, the journal of Middle East petroleum geosciences, since 1995. He was Saudi Aramco's exploration manager in 1989-92 when eight Paleozoic oil and gas fields were discovered in central and northwest Saudi Arabia and one in the Red Sea. He holds degrees in engineering, business, and earth sciences from King Fahd University of Petroleum and Minerals and Stanford, Brown, and Harvard universities.

Ghadames fueling Tunisian oil production growth

The Ghadames basin in southern Tunisia has become a core area for Pioneer Natural Resources Co., Dallas, which is operating or participating in oil and gas-condensate developments on several blocks.

Pioneer is evaluating opportunities to extend its Ghadames basin position into Algeria and Libya.

While it builds oil production facilities this year on the 384,000-acre Jenein Nord Block, Pioneer and other producers are working with the government to evaluate the opportunity to expand infrastructure to supply gas from the southern part of the country to northern Tunisian markets. Jenein Nord is 450 miles south of Tunis.

Playing mainly the Silurian, Pioneer has drilled four new field discovery wells on the Jenein Nord Block since late 2006 with combined multizone gross test rates of 30,000 boed, 85% oil and 15% gas-condensate. Pioneer noted that the combined test rate isn't necessarily indicative of an actual combined production rate.

The company's net production of 5,000 boed as of late May is expected to grow 80% in 2007 with start-up of the Jenein Nord discoveries near the end of the year and 90% in 2008.

The most recent discovery, Shaheen-1, tested at 8,000 boed (OGJ Online, June 8, 2007). The other discoveries are Waha, Cherouq, and El Badr.

Meanwhile, Pioneer has participated in 11 wells with 10 successes on the Adam concession, where Eni SPA is the operator. Production there exceeded 20,000 b/d, and a new discovery went on line in mid-May 2007 at 3,500 b/d.

With a $70 million hike in 2007 capital spending, the company expects to drill at least seven more wells this year. That will include up to four exploration wells on Jenein

Nord and three wells on the adjacent nonoperated blocks. The net position is 3.9 million acres.

Pioneer operates Jenein Nord with 100% interest, and Tunisia's state ETAP has a 50% back-in right.

The company and its partners have acquired 1,200 sq km of 3D seismic, and Pioneer has identified more than 30 prospects on its acreage, some with individual resource potential as large as 25 million boe.

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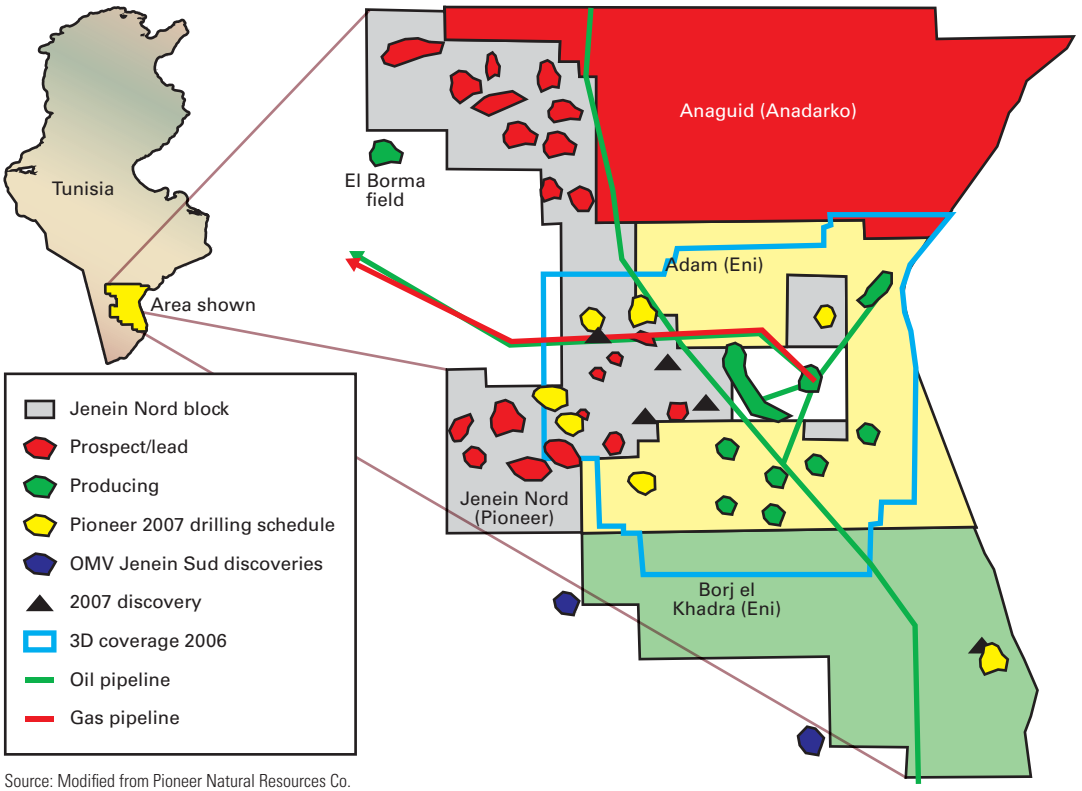
DISCOVERIES, PROSPECTS IN TUNISIA GHADAMES BASIN

Fig. 1



Source: Modified from Pioneer Natural Resources Co.

giant El Borma field, discovered in 1964. Operated by Eni, El Borma averaged 11,000 b/d in 2006 (OGJ, Dec. 18, 2006). OGJ estimated Tunisia's oil production at 95,000 b/d in March 2007, up 41% on the year (OGJ, June 11, 2007, p. 70). Eni, which has operated in Tunisia since 1963, operates Borj el Kadra with 50% interest, Talisman Energy Inc. has 30%, and Pioneer has 20%. ENI produced 17,000 boed in Tunisia in early 2007.

Anadarko Petroleum Corp. operates the 1.1 million acre Anaguid Block, where it made two discoveries in 2003. Chaabet El Merkanti-1 cut 95 ft of pay and tested 4 MMcfd of gas and 500 b/d of condensate. Samet El Anaguid-1 cut 52 ft of net pay in the same formation. Development plans have not been filed for either discovery.

Also active in the Ghadames basin on the 100% owned Chouech Es Saida and Ech Chouech concessions south of El Borma is Winstar Resources Ltd., Calgary.

Winstar finalized agreements in May with the Tunisian Ministry Energy, Eni, and the Tunisian national gas and electricity utility to process and sell associated gas from Chouech Es Saida, where at the time it was producing 1.4-1.5 MMcfd. Winstar planned to cease flaring and begin selling gas in mid-May. The gas was to be transported to the El Borma concession through an 80-km, 100% owned pipeline with Winstar receiving $7-7.50/Mcf.

Net oil production, 1,550 b/d with one well down due to a failed pump, was expected to be closer to 1,900 b/d with the start-up of gas sales compared with 200 b/d a year earlier. ✦

North Dakota

Paramount Resources Ltd., Calgary, is rigging up two rigs newly built by the company to drill horizontal Bakken shale/Birdbear oil wells in western North Dakota.

The company has acquired lands with more than 100 development locations since early 2005 and is still pursuing acreage.

The current Williston basin play is based on the ability to perform massive open-hole fracs in wells 15,000 ft deep with laterals as long as 5,000 ft in the Bakken, the company said. Wells are completed at 500 b/d or more, and ultimate recovery is expected to average 250,000 bbl/well.

Texas

South

Riverdale Oil & Gas Corp., Huntington Beach, Calif., plans to develop oil in Cretaceous San Miguel 40 miles south of San Antonio.

The company plans to reperforate the Hitzfelder-10 well in the San Miguel at 2,950 ft and run a hydraulic frac using a proprietary system to facilitate the mobility of the oil. It estimated 240,000 bbl of oil and 120 MMcf of gas in place on 40 acres with the possibility of 15% recovery.

FX Energy drilling in Poland's Permian basin

Nina M. Rach
Drilling Editor

FX Energy Inc., Salt Lake City, focuses on conventional oil and gas resources in Poland's Permian basin.

FX Energy says Poland is underexplored; only one company was actively exploring in the country in the 50 years it was closed to the West. FX Energy has 3.2 million gross (2.7 million net) acres under lease, predominantly in the central lowlands of western Poland.

The company's first production began in 2006 and it estimates it will produce 6 MMcfd equivalent from three wells in 2007, generating revenues of $15 million (Fig. 1).[1]

NOC

Based in Warsaw, Polskie Górnictwo Naftowe i Gazownictwo Spolka Akcyjna (PGNiG SA) is the largest Polish oil and gas exploration and production company. As the national oil company, it is commonly known abroad as the Polish Oil and Gas Co. (POGC).

In addition to operating within Poland, POGC said in its 2005 annual report that the company's international strategy includes acquiring exploration and operating licenses abroad "individually and jointly with interested Polish and foreign parties."[2]

POGC spent about €110 on exploration in Poland in 2005, working in the Carpathians, Carpathian foothills, and Polish lowlands.[2]

FX project areas

FX has five main concession areas in Poland: Fences I, II, III; Northwest; Block 287; Kutno; and Block 255.

• The Fences project area covers 300,000 acres in western Poland's Permian basin. FX Energy currently holds a 49% interest and POGC holds 51%. The three concession areas surround POGC's Radlin field (390 bcf).

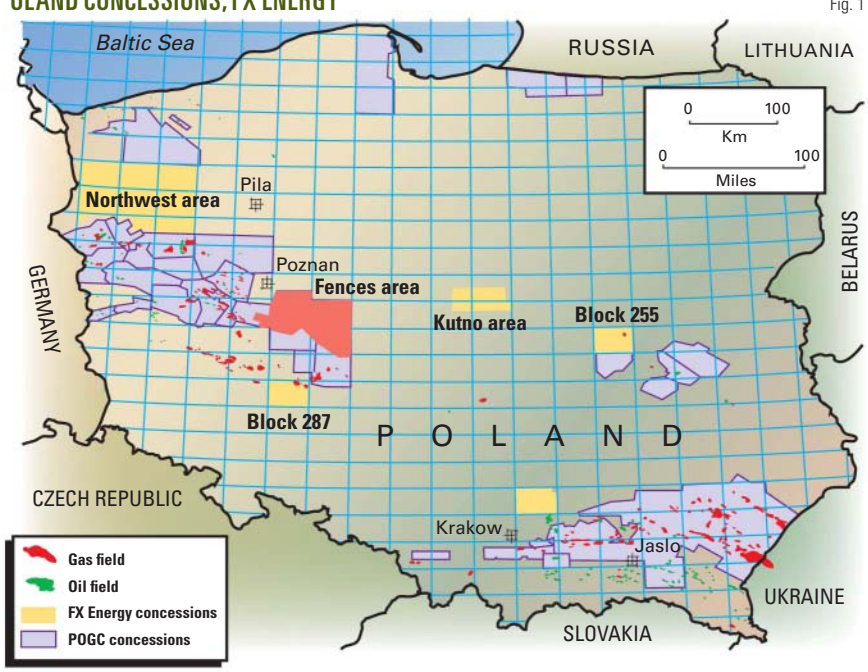
The Fences area is so named because when FX took the concession, the agreement was that any existing production controlled by POGC would be fenced off. Boundaries of the producing fields were delineated by seismic data, FX Energy told OGJ.

The Fences concession holds four main areas of interest: Sroda area in north (3D seismic currently in processing for delineating additional wells); Ca2 area in northeast (test well approved for second-half 2007); Lubinia area in east (3D or drilling decision coming); and the "pinch-out" area in the southwest ("medium term" prospect).1

The Zaniemysl-2 well, drilled in Fences I area in 2003-04, targeted the top of the Rotliegendes sandstone at

POLAND CONCESSIONS, FX ENERGY

Fig. 1



Gas flares in the left photo below during a drillstem test at the Roszkow well in May 2007 (Fig. 1; photo from FX Energy Inc.). FX Energy drills the Roszkow well in the right photo below in February 2007 (Fig. 2; photo from FX Energy).

DRILL RIGS AVAILABLE IN POLAND*

Table 1

Rig type	Hook load, tonnes	Max. nominal power, kN
Rigs available for Fences area		
F–400–4DH	400	3,000
National 110 UE	454	1,500
IRI–E-1200	309	1,200
Skytop TR-800	185	950
Smaller rigs available for other Polish concession work		
KREMCO K-600	105	475
Skytop RR-600	125	575
Skytop RR-750	136	650
IRI-750	136	700
IDECO DIR-700	115	700
Cabot-750	136	800
KREMCO K-900	168	900

*Data from FX Energy Inc.

about 2,940 m. It was spud in October 2003 and reached 2,850 m TD in 2004.

FX Energy has drilled the Sroda structure in Fences II area. The current producing well, Sroda-4, was drilled to 3,600 m, has 33 m net pay at 20-24% porosity and 8.8 md permeability, and produces 5 MMcfd.[1] The company began drilling the Roszkow well in February 2007, reached TD at 2,900 m, and ran a drillstem test in May 2007 (Fig 2). The well was being tested when this issue went to press in June.

FX is waiting for production facilities for the Sroda-4, Winna Gora, and Roszkow wells.

• The Northwest-Szczecin is a deep Rotliegend play extending from Germany. The company has 100% interest in 1.6 million acres.

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DRILLBITS USED IN FENCES AREA*

Table 2

Bit	OD, in.	ROP, m/hr	Stratigraphy	Type
Tricone bit 115	17½	5-9	Jurassic	BM1X, BM1HVXC
Tricone bit 115		6-15		BM1ZXC, BM1HVXC
Tricone bit 437-447 PDC	12¼	4-7	Rhaetian Kauper	GF15BDVC, FGS10CPS GFS15BDVC, GFS10BVC
		2-6	Muschelkalk Bundsandstein	M42HPX, MGR84PX, M72PX, MA89PX
Tricone bit 447 PDC	8½	5	Zechstein	F15PS M37PX, M72PX, M616VSPX, FM2841
PDC	5⅞	8-11 5-18	Rotliegende	MA62QPX, M16VPX

*Data from Jaslo Oil and Gas Exploration Co.

DRILLING FLUIDS, FENCES AREA*

Table 3

Bit diameter, in.	Type of mud	Specific gravity
24	Bentonite	As low as possible
17½	Bentonite	As low as possible
12¼	Potassium	1.25
8½	Salty barite	2.35
5⅞	Salty polymer with blocators	1.2

*Data from FX Energy Inc.

FORMATIONS IN FENCES I, II, III AREAS*

Table 4

Formation description	Average formation — thickness, m — Deep well	Medium well
Quaternary + Tertiary—sand, mud, clay, lignite	140	150
Jurassic—claystone, mudstone, sandstone, limestone, marl,	900	230
Rhaetian—claystone, mudstone, sandstone	390	480
Kauper—claystone, sandstone, mudstone, salt, anhydrite	550	525
Muschelkalk—limestone, dolomite, claystone, marl	260	250
Upper Bundsandstein (Ret)—claystone, marl, dolomite, anhydrite	120	300
Middle Bundsandstein—sandstone, mudstone, limestone	580	100
Lower Bundsandstein—claystone, mudstone, dolomite		200
Zechstein—salt, clay, anhydrite, carbonate rocks	600	480
Rotliegende—sandstone, conglomerate, mudstone	100	100
Average well depth	**3,650**	**2,850**

*Data from FX Energy Inc.

FORMATION CHARACTERISTICS, WESTERN POLAND

Table 5

	Porosity, %	Permeability, md	Formation pressure gradient, MPa/m
Quaternary + Tertiary	<30	<50	<0.01
Jurassic	<30	<100	<0.01
Bundsandstein	<20	<100	<0.011
Main dolomite	<10	<10	<0.023
Rotliegende	<27	<600	<0.011

*Data from FX Energy Inc.

- The Block 287-Grabowka area covers 213,000 acres; FX Energy holds 100% and plans to reenter three gas wells this year.
- FX Energy characterizes the Kutno structure as the "largest undrilled structure onshore Europe."[1] The company holds 100% interest in 284,000 acres.
- The Pomerania project area covers 2.2 million acres in western Poland's Permian basin. FX Energy currently holds a 100% interest in the Pomerania project area except for one block of 225,000 acres, where its interest is 74% and POGC holds 26%.
- The Wilga project area, Block 255 covers 250,000 acres in east-central Poland. FX Energy holds 82% interest.

Partners

In October 2002, FX Energy signed a memorandum of understanding with CalEnergy Gas Ltd., an affiliate of MidAmerican Energy Holdings, Des Moines, Iowa, jointly to explore certain property interests in Poland (OGJ Online, Oct. 30, 2002).

In January 2003, FX Energy entered into a farmout agreement for the Fences I project area with CalEnergy, sharing 49% interest (OGJ, Feb. 16, 2004, p. 39).

FX Energy's Scott Duncan told OGJ that the relationship remains the same in 2007.

After the 2004 discovery, FX defined the Greater Zaniemysl area. Duncan said the partners have not drilled since the second well was completed in 2004.

Houston-based Apache Corp. drilled about a dozen wells in partnership with FX Energy in the Pomeranian concession, in the Carpathians, and in the Wilga area.

The Tuchola 108-2 wildcat in the Pomeranian concession tested 9.5 MMcfd of gas from the Permian Main dolomite at 8,318-514 ft (OGJ Online, Jan. 15, 2001, p. 8).

The partnership generated a single producing well. Apache left Poland in January 2005. FX Energy continues to operate the single well in the Wilga area in central Poland, which produces 150 bo/d and 3 MMcfd natural gas (82% FX Energy; 18% POGC).[1]

Drilling contractors

Three core companies controlled by POGC perform contract drilling services:

- Kraków Sp. z o.o.
- Jaslo Sp. z o.o.
- NAFTA Sp. z o.o. Pila.

FX Energy has drilled with Jaslo Drilling Co. and Pila Drilling Co., under an open bidding system. FX Energy told OGJ that the Krakow drilling company mainly operates abroad, using rigs which could be used in FX's operational regions in Poland.

London's Aurelian drills its first well in Poland

Aurelian Oil & Gas PLC, a London-based exploration and production company, prospects in central Europe: Poland, Romania, Slovakia, and Bulgaria (OGJ, Apr. 23, 2007, p. 8).

Through its wholly owned subsidiary, Aurelian Oil & Gas Poland Sp. z o.o., the company operates Polish concessions in two areas: Poznan East in Poland's central lowlands and Bieszczady in the southeast, along the productive Carpathian trend, which follows the mountain belt from Austria in the west, through the Czech and Slovak Republics, Poland, and into the Ukraine and Romania (www.aurelianoil.com).

Poznan East

Aurelian's 90% Polish subsidiary, Energia Zachod Sp. z o.o., holds 100% of two concessions in the Poznan East area. The Polish licensing authorities executed the Mining Usufruct agreement (MUA) in September 2002 and granted the 6-year concessions in February 2003.

Aurelia acquired seismic in first-half 2006 and selected a drilling location.

In November 2006, Energia Zachod announced it had signed a contract with Oil & Gas Drilling "Nafta" Ltd. of Pila to drill the Trzek-1 appraisal well on the Siekerki structure. This is Aurelian's first well in Poland.

State oil company POGC drilled four wells on the Siekerki structure in the 1970s, all with gas shows in the Permian Rotliegendes formation. The Rotliegendes formation is the reservoir in the giant Groningen field in the Netherlands and the main gas producing horizon in the UK and Dutch sectors of the Southern North Sea. Aurelian says the eastern end of this gas-producing basin lies in the Polish central lowlands.

Aurelian prepared the Siekerki drill site during the winter and spudded the Trzek-1 well on Mar. 7, 2007, east of the city of Poznan. Drilling was expected to take 3½ months.

Roy Hartley, Aurelian's operations director, told OGJ that the Nafta Pila rig has a Upetrom mast, substructure, hook, rotary, and swivel with 320 ton capacity; Italian 1,700 hp drawworks, and two National 1,300-hp mud pumps, forming "a very effective rig."

On May 16, 2007, Aurelian's Managing Director Michael Seymour, announced the "well being drilled at Trzek is progressing, although the drilling has been harder than originally anticipated." He said the target depth is below 3,000 m.

Carpathian blocks

Aurelia has 100% interest and operatorship in three Carpathian blocks (Swidnik, Medzilaborce, and Snina) in Slovakia, abutting the Polish and Ukrainian borders. These licenses began Aug. 1, 2006, and cover about 2,480 sq km.

On Apr. 2, 2007, Seymour said the company was reprocessing existing seismic data over the Carpathian blocks and expected to begin additional seismic work in early 2008, adding, "We may seek a partner to share the exploration risk."

Bieszczady blocks

In November 2006, Aurelian signed initial agreements with Eurogas Polska Sp. z o.o. that will lead to Aurelian taking a 25% interest in several blocks in Poland's Bieszczady area (bordering Ukraine).

The Bieszczady blocks are adjacent to the company's Carpathian blocks in Slovakia.

Aurelian's assumption of interest in Bieszczady remains subject to the issue of a new MUA between the Polish licensing authorities and Polskie Gornictwo Naftowe i Gazownictwo SA (PGNiG; exploration and production arm of POGC) and a joint operating agreement between PGNiG, Eurogas Polska, and Aurelian. PGNiG will hold the MUA and the concessions on behalf of itself (50%), Eurogas Polska (24%), and Aurelian (25%).

In his Managing Directors Report, issued Apr. 2, 2007, Seymour said "Aurelian will pay Eurogas' 25% share of the first €10 million of the work program which should include 500 km of new 2D seismic and at least one well."

On May 16, 2007, Aurelian announced that "the joint operating agreement is expected to be signed this month and will be followed by the acquisition of 2D seismic during the summer months."

Oil & Gas Exploration Co. Jaslo Ltd. (Jaslo Drilling), Jaslo, southeast of Krakow, in eastern Poland. Jaslo drilled the Zaniemysl-2 well for FX Energy in 2004 in the Fences 1 project area of western Poland's Permian basin (OGJ, Feb. 16, 2004, p. 39).

Oil and Gas Drilling Co. NAFTA Ltd. (OGDC) is based in Pila, Poland, and has been owned by POGC (100%) since 1998. OGDC performs contract drilling and workover services through Pila Oil & Gas Co. (Pila), with Polish national crews.

Pila has 10 land rigs that have worked in Poland, Hungary, Sweden, Algeria, Syria, Iraq, Pakistan, and India (OGJ, Jan. 23, 2006, p. 35). The fleet includes several types of single, double, and triple-stand rigs with top-drives and kelly's: Massarenti Mas 6000 E; National 110 UE; IDECO (1200, 1000, 750); F-200; and P-80 (www.nafta.com.pl).

FX Energy told OGJ that four main rig types can drill in the Fences area, western Poland (Table 1). Hook loads range from 185-454 tonnes, and maximum nominal power ranges 950-3,000 kN.

Seven smaller rig types operate

elsewhere in Poland, with hookloads of 105-168 tonnes and maximum nominal power 475-900 kN (Table 1).

Drilling parameters

FX Energy told OGJ that all types of rock bits are used in the Fences area: tricone mill tooth and insert bits, PDC bits, as well as PDC and diamond coring bits where necessary. Jaslo Drilling provided rate of penetration data for four types of drillbits used in the Fences area (Table 2).

Several contractors provide drilling fluid services with various chemicals available. FX Energy said several types of drilling mud are used in operations at Fences area (Table 3):

- Top hole (24, 17-in. bit) is drilled with bentonite and low sp gr.
- After surface casing, potassium mud is used with a 12¼-in. bit, 1.25 sp gr.
- Using an 8½-in. bit, salty barite mud is used with 2.35 sp gr.
- Final drilling to TD with a 5⅞-in. bit, salty polymer mud, and 1.2 sp gr.

Formations

The formations in the Fences I, II, and III concessions in western Poland include the Quaternary; Tertiary; Jurassic; Rhaetian; Kauper; Muschelkalk; Upper, Middle, and Lower Bundandstein; Zechstein, and Rotliegende (Table 4). Average depth of a medium well is 2,850 m; a deep well averages 3,650 m.

Porosity and permeability of the formations drilled in Poland's Permian basin range from the tight main dolomite (Lower Bundsandstein) at 10% and 10 md, to 27% and approaching 600 md in the productive Rotliegende sandstones (Table 5). ✦

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Models provide insights on North American gas future

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Models using a history match of past production and a bell-curve approach provide an insight to the various estimates for ultimate recovery of conventional and unconventional gas resources in North America.

The assessment will model natural gas production in North America to 2130, except for gas hydrates.

Conventional gas

Published estimates of ultimate recovery resources (URR) for conventional gas in North America vary markedly. In particular, Laherrere estimates 42.5 trillion cu m (tcm) for US and Canada,[1] whereas Rempel estimates 69 tcm for US, Canada, Mexico, and Greenland.[2]

Greenland and Mexico combined have about 6 tcm of estimated URR.[3] The URR estimates, therefore, for US and Canada differ by about 20 tcm.

To determine a likely URR estimate for North America, the assessment used a model with various assumptions.[4]

Model 1 used Laherrere's URR estimate of 42.5 tcm for US plus Canada, and Model 2 used Rempel's URR estimate of 63 tcm for US plus Canada.

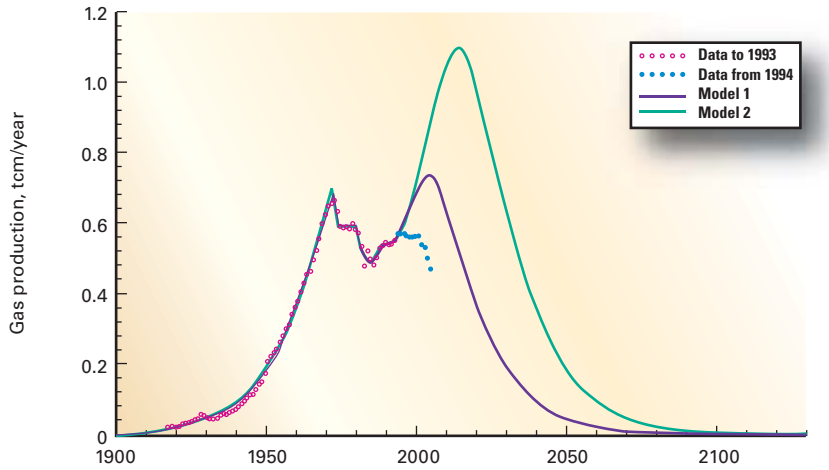
Conventional gas production data exclude coalbed methane, shale gas, and US tight gas and were obtained from a variety of sources.[5-14] Data from these sources unfortunately include Canada's tight-gas production.

Canada produces about 10-12 billion cu m/year from tight-gas sands.[15,16] Accordingly, both models add a Canadian tight-gas URR estimate of 2 tcm to the conventional URR estimates.

Fig. 1 illustrates the predictions. Both models used only historic US and Canadian conventional natural gas production from 1918 to 1993.

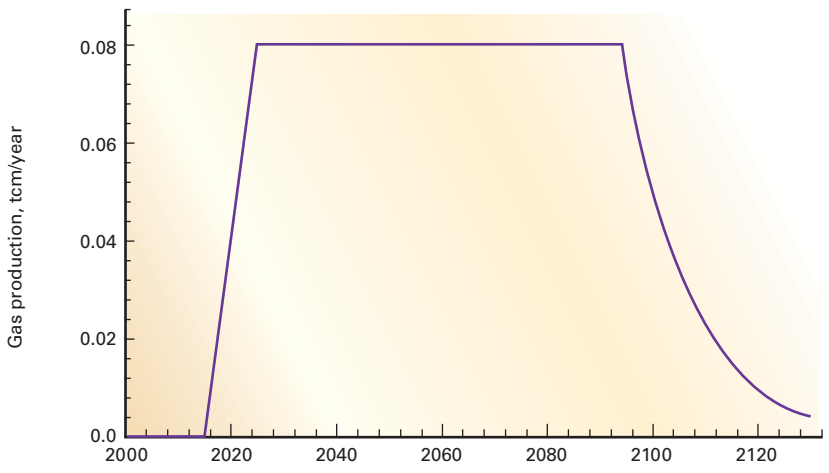
NORTH AMERICAN CONVENTIONAL GAS

Fig. 1



NORTH AMERICAN STRANDED GAS

Fig. 2



The figure shows that from 1994 to 2005 the modeled production deviates from historic data that plateau from 1995 to 2001. Both models increase production in this period.

Model 1 peaks in 2003 and rapidly declines, which is similar to the production data that decrease rapidly from 2001 onwards. Model 2 peaks in 2011 before rapidly declining. Both models appear not to predict future production well.

To provide a better prediction, the assessment modified both models to account for stranded gas. From literature, northern North America has about 6.7 tcm of stranded gas.[17,18] Production of this gas cannot begin until the industry builds pipelines, and it is uncertain when those pipelines will be completed. An estimate places the date at about 2015 or slightly earlier.[18]

Estimates also indicate that the pipelines will have a maximum gas flow

capacity of about 7.8 bcfd.[18]

Production from stranded North American gas with a 7-tcm URR can be simply modeled by assuming production increases linearly from completion of the pipeline to a maximum production pipeline capacity, followed by an exponential decline (Fig. 2).

The stranded gas was incorporated into modified versions of Models 1 and 2, which used production data to 2005 and consequently reduced the conventional unstranded gas URR estimates by 7 tcm, to obtain 37.5 and 58 tcm, respectively (Fig. 3).

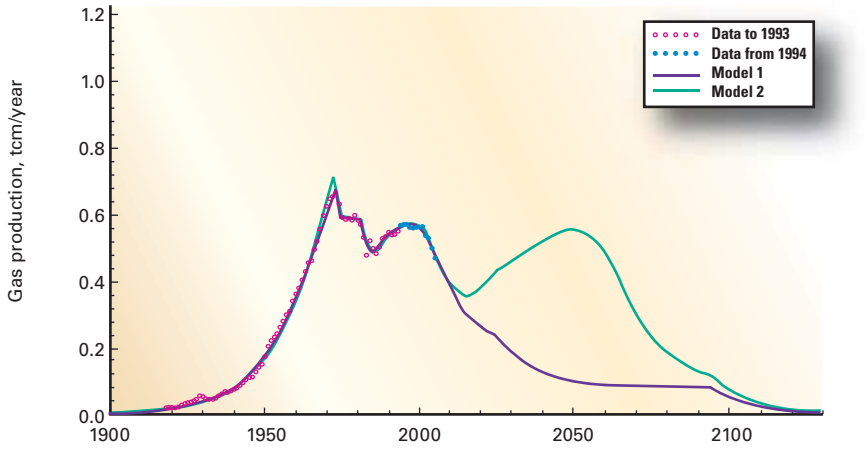
The two models produce different estimates of future conventional gas production. Model 1 predicts gas production will decrease steadily. Conversely, Model 2 shows a continued decrease until 2015, followed by a significant increase in production to a peak in 2049.

Of the two predictions, Model 2 is more unlikely, given the increasing reliance on unconventional gas, which now supplies more than 30% of US and Canada's natural gas. Why develop expensive unconventional gas if large amounts of conventional reserves exist?

In looking at the US URR estimate, which is calculated as the sum of produced, reserves, and resources, the production and reserves estimates of 28.7 tcm and 5.6 tcm, respectively, appear to be values of combined unconventional and conventional gas, contradicting its claim of being a conventional gas assessment.[3]

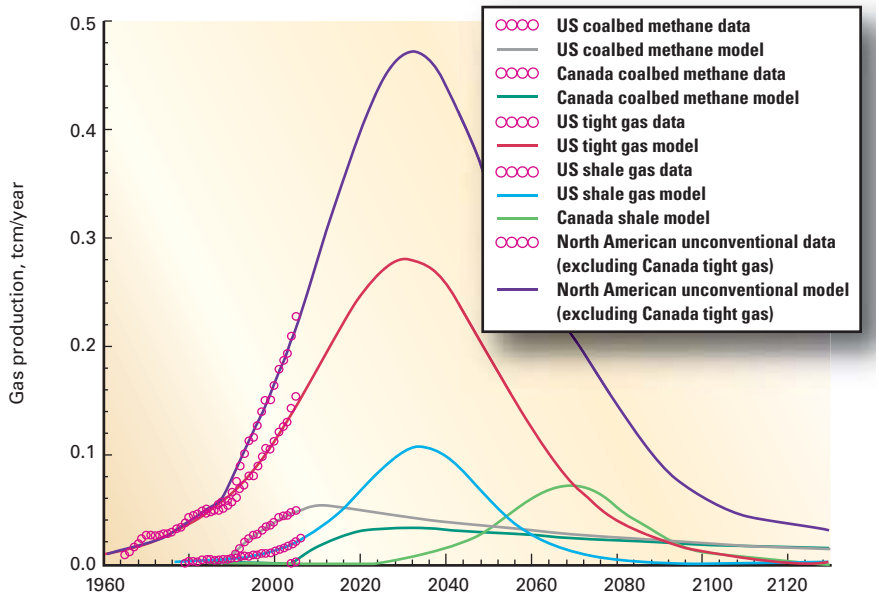
Conventional and stranded gas

Fig. 3



Unconventional gas

Fig. 4



Unconventional gas

The assessment also can include unconventional gas in the model. URR estimates of unconventional gas in the US are:

- Tight gas: 200-627 tcf.[11 19-22]
- Coalbed methane: 50-180 tcf.[9 23 24]
- Shale gas: 50-150 tcf.[8 11 24]

The model used the highest estimates of 600 tcf (17 tcm) tight gas, 180 tcf (5 tcm) coalbed methane, and 150 tcf (4.2 tcm) shale gas.

As stated earlier, Canada also produces tight gas, but the production data are unavailable. The model, therefore, adds 2 tcm (70 tcf) to the URR estimates to accommodate Canadian tight-gas production.

Estimates of tight-gas resources in Canada vary from 300 tcf to 700 tcf.[15 25-27] The US has about 6,000 tcf of tight gas in place, and as stated the URR is about 600 tcf, which equates to about a 10% recovery.[28] The model assumes Canada's tight-gas URR is 70 tcf (2 tcm), which is 10% of the highest resource estimate.

The 70-tcf estimate is optimistic given current recoverable estimates are 10-15 tcf.[15] Estimates are that Canada's coalbeds hold 167 tcf of recoverable gas,[18] and its shale gas resources are at least 860 tcf,[29] although "tens of thousands of tcf" may be in place.[30]

The model assumes a recovery of 100 tcf of Canadian shale gas.

The shale and tight-gas models use bell curves for estimating production.

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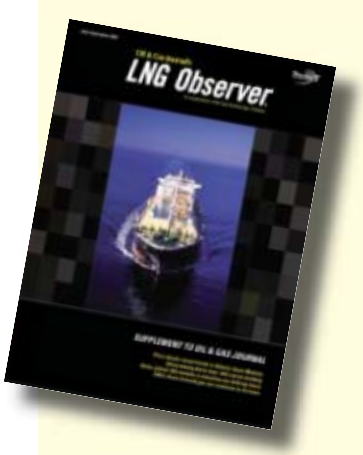

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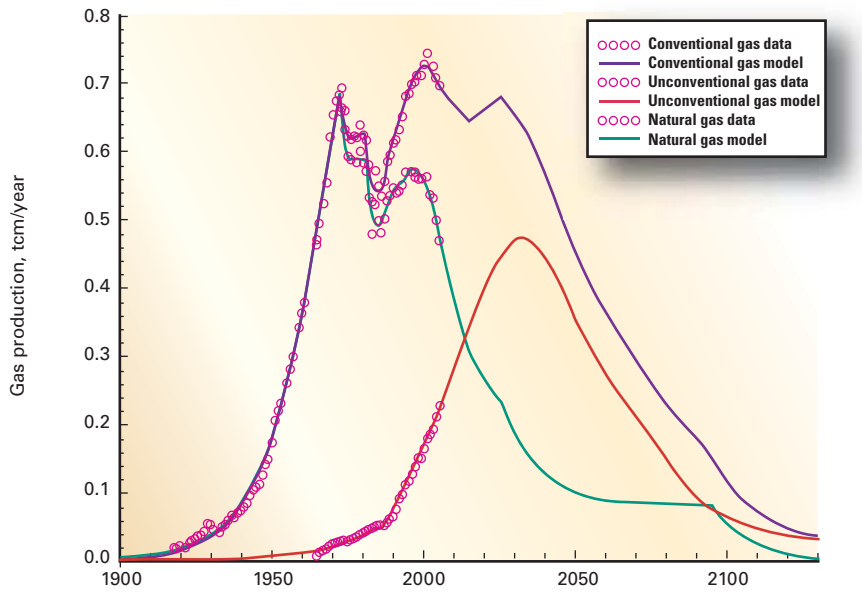
NORTH AMERICAN GAS

Fig. 5



EQUATIONS

$$y = a' x^2 + b' x + c' \quad (1)$$

$$M(x) = \begin{cases} a(x - x_d)^2 - bc(x - x_d) + c & \text{for } x \le x_d \\ ce^{-b(x-x_d)} & \text{for } x > x_d \end{cases} \quad (2)$$

Where

$a = a'$

$$b = -\frac{b' + 2a' x_d}{a' x_d^2 + b' x_d + c'}$$

$c = a' x_d^2 + b' x_d + c'$

Canada still does not have shale-gas production; therefore, the model assumes that the bell curve slope for Canada is the same as for the US shale model. Production is assumed to start in 2010 at 1% of maximum.

The coalbed methane model works by fitting a parabola, Equation 1 (see equation box), to the production information, which are data for the US[7] and prediction for Canada.[16 18]

At the year x_d the function shifts to an exponential decay. The model solves the variable x_d to ensure that the area under the graph agrees with the URR estimate of the coalbed model (Equation 2).

Fig. 4 shows the unconventional gas models.

Adding these models to the Model 1 for North American conventional gas provides an outlook of future natural gas production (Fig. 5).

Because of unconventional and stranded gas, production remains almost steady until 2025 before declining.

North America is no longer self-sufficient in natural gas and requires more LNG imports to ensure meeting future gas demands.

Finally, a word of caution: URR estimates are only estimates. In a 30-year timeframe, they may be low or high. More production data will provide better future estimates. In particular, the model used for Canada's shale gas is highly speculative. Also a lack of a tight-gas definition in Canada and limited unconventional data also create considerable uncertainty.

Acknowledgments

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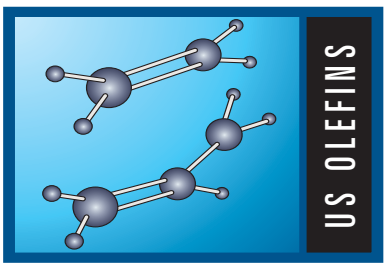
FIRST-HALF 2007

Gasoline price spike shifts ethylene feeds

Dan Lippe
Petral Worldwide Inc.
Houston



Extraordinary price volatility in the motor gasoline market had a significant effect on spot prices and price-value relationships for ethylene feedstocks; but prices for primary coproducts lagged the surge in gasoline and feedstock prices. These shifts in feedstock and coproduct price relationships, in turn, influenced ethylene production costs and prompted ethylene producers to make significant changes in feed slates.

Gasoline prices and octane values are significant factors that affect prices for light naphtha feedstocks and key coproducts including propylene, benzene, toluene, and xylenes (BTX). We measure relative strength in gasoline prices using the price differentials between unleaded regular gasoline and West Texas Intermediate (WTI) crude, and we measure octane values using the price differentials between unleaded regular and unleaded premium gasoline.

During first-quarter 2007, refiners normally conduct late-winter turnarounds and complete major maintenance projects before the seasonal increase in gasoline demand. Usually the decline in gasoline production occurs when demand for gasoline is near its lowest level of the year and reduced supply has a minimal effect on prices.

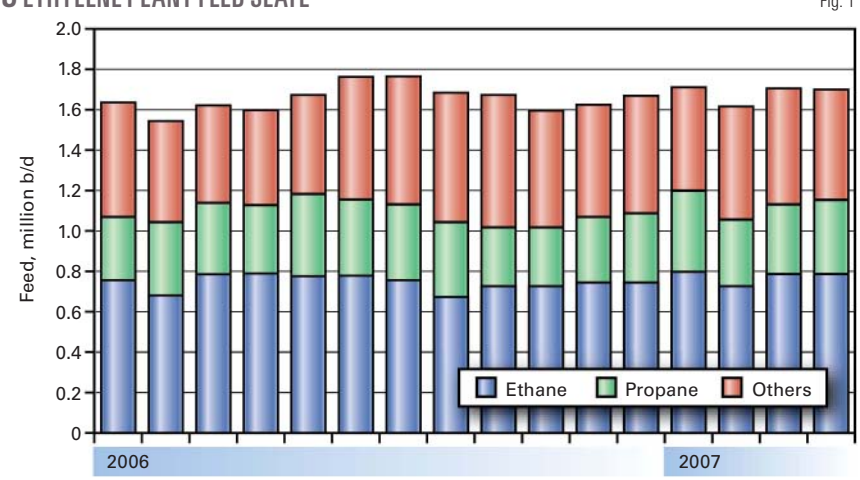
This year, however, according to US Energy Information Administration statistics, motor gasoline imports during March-May 2007 were 200,000-300,000 b/d lower than year-earlier volumes. This unexpected fall in supply compounded the seasonal decline in refinery production; total inventories of motor gasoline declined to a low of 193-194 million bbl (more than 15 million bbl lower than in March 2006) according to EIA's Weekly Petroleum Status Report.

During fourth-quarter 2006, unleaded regular gasoline-WTI differentials averaged 12.7¢/gal and were significantly narrower than during third-quarter 2006. Additionally, these differentials during fourth-quarter 2006 were only 5.6¢/gal higher than the average for 2001-04.

Unleaded-WTI differentials on the US Gulf Coast remained at reasonable levels in January 2007 but increased to 41.2¢/gal in March and jumped to 80-82¢/gal in May 2007, a new record high for the monthly average.

US ETHYLENE PLANT FEED SLATE

Fig. 1



Source: Petral Monthly Olefin Plant Feedslate Survey

Olefin plant feed slates

Ethylene industry demand for fresh feed averaged 1.64 million b/d in fourth-quarter 2006 and increased to 1.69 million b/d in first-quarter 2007. Demand for LPG feedstocks (ethane, propane, and normal butane) averaged 1.13 million b/d in fourth-quarter 2006 and increased to 1.2 million b/d in first-quarter 2007.

Ethylene producers cracked a lighter feed slate in first-quarter 2007. Specifically, LPG feeds accounted for 71% of total fresh feed in first-quarter 2007 vs. 69% of fresh feed in fourth-quarter 2006. The shift to lighter feeds continued in April; LPG feeds accounted for 73.6% of total fresh feed. LPG feeds' share of total fresh feed was previously at this level in May 2006.

Table 1 shows trends in olefin plants' fresh feed slates.

Based on projected ethylene industry operating rates of 90-92%, total demand for fresh feedstocks will average 1.70-1.75 million b/d during second and third quarters 2007. Total demand for LPG feedstocks will average 1.23-1.25 million b/d; LPG feedstocks will account for 71-73% of total fresh feed during second and third quarters 2007.

Fig. 1 shows historic trends for ethylene feed slates.

Ethylene production

Ethylene production from fresh feed totaled 13.36 billion lb in first-quarter 2007 (Table 2). Ethylene production from steam crackers was 54 million lb less than in fourth-quarter 2006 (less than half a day's output).

Production from LPG plants totaled 4.78 billion lb in first-quarter 2007 and was 173 million lb less than in fourth-quarter 2006 (about 3 days of production). Production from multifeed crackers totaled 8.59 billion lb in the first quarter and was 119 million lb more than during fourth-quarter 2006 (about 1.5 days of production).

LPG crackers operated at 89% of nameplate capacity (21.6 billion lb/year) during first-quarter 2007. Multifeed crackers operated at 87% of nameplate capacity (40.2 billion lb/year) during first-quarter 2007.

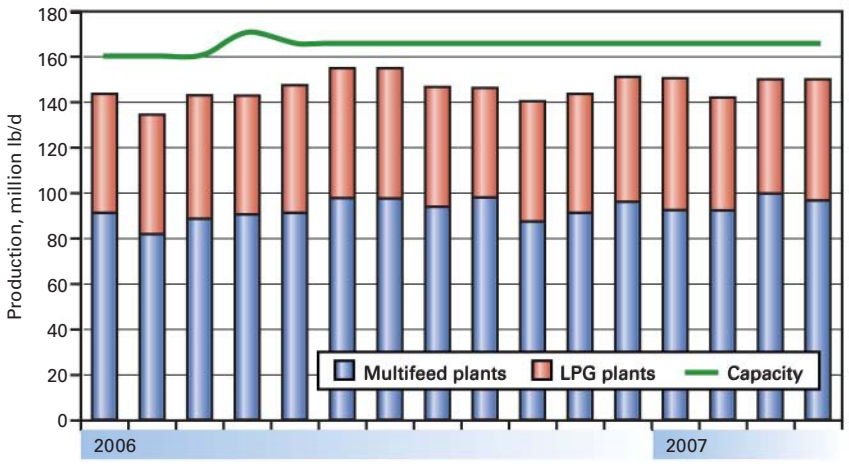
Huntsman Corp.'s ethylene plant in Port Arthur, Tex., remained out of service pending repairs to damage resulting from a fire in late April 2006. Furthermore, Huntsman announced the sale of this plant and other basic petrochemical assets to Flint Hills Resources LLC (a wholly owned subsidiary of Koch Industries, Inc.) in February 2007.

When the ethylene plant at Port Arthur—a multifeed cracker with 1.55 billion lb/year nameplate capacity—returns to service, nameplate ethylene production capacity for multifeed crackers will total about 41.8 billion lb/year.

Fig. 2 shows trends in ethylene production.

US ETHYLENE PRODUCTION

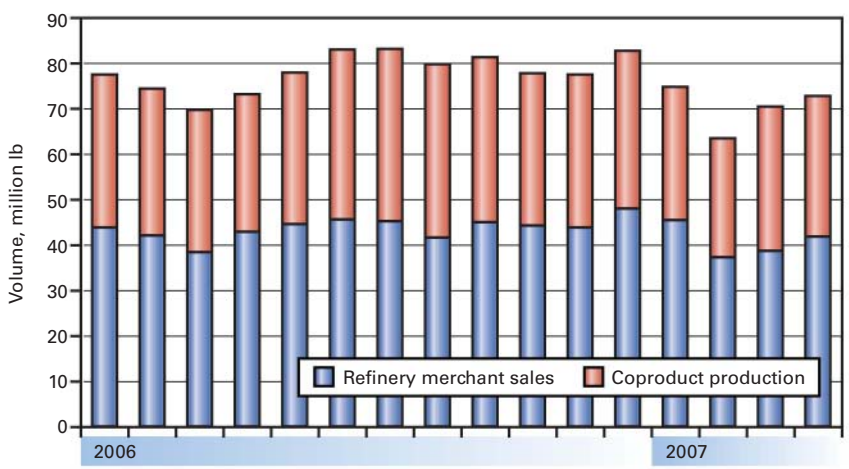
Fig. 2



Source: Petral Monthly Olefin Plant Feedslate Survey

PROPYLENE PRODUCTION, SALES

Fig. 3



Source: Petral Monthly Coproduct Supply Analysis

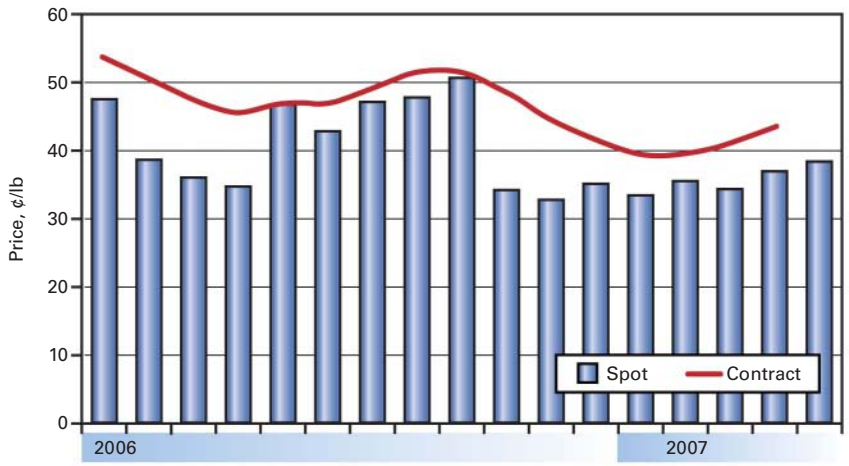
US propylene production

Propylene from steam crackers was 3.1 billion lb in first-quarter 2007, which was 52 million lb less than in fourth-quarter 2006. Propylene production from LPG crackers totaled 462 million lb in first-quarter 2007 and was equal to production in fourth-quarter 2006.

Propylene production from multifeed crackers was 2.63 billion lb in first-quarter 2007, which was 45 mil-

ETHYLENE PRICES

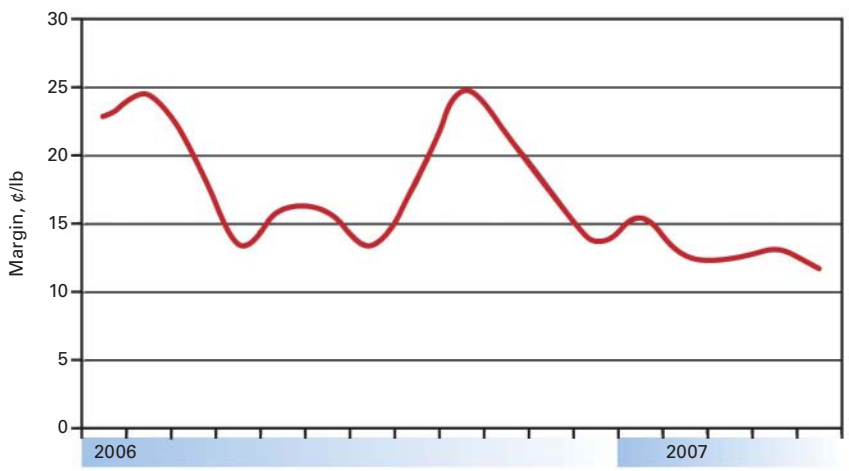
Fig. 4



Source: Petral market research

ETHYLENE PROFIT MARGIN

Fig. 5



Source: Petral analysis

lion pounds less than during fourth-quarter 2006. Operating rates for multifeed crackers were essentially the same in fourth-quarter 2006 and first-quarter 2007. Ethane's share of fresh feed in multifeed crackers, however, increased to 31.1% in first-quarter 2007 vs. 28.8% in fourth-quarter 2006. The shift to a lighter feed slate, to some extent due to rising prices for motor gasoline, accounted for the decline in coproduct propylene production from multifeed crackers.

Table 3 shows trends in coproduct propylene production from LPG and multifeed plants.

Refinery propylene supply

Production trends during first-quarter 2007 were in-line with typical seasonal patterns. Refinery merchant propylene sales (Table 4) were 1.42 billion lb in January 2007 (45.8 million lb/day) but fell to 1.05 billion lb in February 2007 (37.6 million lb/day).

EIA reported a strong rebound in March with total production of 1.34 billion lb (43.4 million lb/day). Production for the first quarter totaled 3.82 billion lb, 380 million lb less than during fourth-quarter 2006.

Based on expected refinery operating rates, gasoline production, and FCCU feed rates, merchant sales of refinery grade propylene will increase to 4.1-4.2 billion lb in second-quarter 2007. Refiners have extraordinary incentives to operate at full capacity rates and to maximize gasoline production. By-product propylene production may be at record high volumes during second and third-quarter 2007.

Fig. 3 shows trends in coproduct and refinery merchant propylene sales.

Ethylene economics, prices

Feedstock prices, coproduct values, and ethylene plant yields determine ethylene production costs. We maintain direct contact with the olefin industry and track historic trends in spot prices for ethylene and propylene. We use a variety of sources to track trends in feedstock prices.

Some ethylene plants have the necessary process units to convert all coproducts into high-purity streams. Some ethylene plants, however, do not have the capability to upgrade mixed or crude streams of various coproducts and sell some or all their coproducts at discounted prices. Our estimates of ethylene production costs in this article are based on all coproducts valued at spot prices.

Ethylene production costs

During first-quarter 2007, spot prices for all feedstocks and coproducts increased. Spot prices for natural gasoline increased 19% and spot prices for light naphthas increased 27.5% during January-March. Spot prices for propane, however, increased only 16.5% and spot prices for purity ethane and normal butane increased only 12.9%.

These price increases occurred well before the motor gasoline prices hit their peak in May. Divergence between spot prices for light feeds and heavy feeds occurred during first-quarter 2007 and continued during April and May.

Spot prices for all major coproducts also increased during the first quarter but spot prices for propylene were only 5.5-6.0% higher in March than in Janu-

US ETHYLENE FEED SLATE

Table 1

	Feed type, 1,000 b/d			
	Ethane	Propane	n-Butane	Naphthas, gas oils
2006				
July	762.4	376.1	139.5	495.6
August	676.9	373.9	122.3	520.2
September	728.4	295.1	87.6	569.3
October	729.8	290.6	78.0	509.4
November	752.3	323.6	68.2	493.6
December	752.0	341.6	61.2	519.1
2007				
January	802.7	402.9	32.8	484.3
February	733.7	326.5	72.0	493.5
March	796.2	341.1	84.9	489.0

Source: Petral Monthly Olefin Feedslate Survey

ETHYLENE FROM US STEAM CRACKERS

Table 2

	Production, billion lb		
	LPG crackers	Multifeed crackers	Total
2006			
July	1.8	3.0	4.8
August	1.6	2.9	4.6
September	1.5	3.0	4.4
October	1.6	2.7	4.4
November	1.6	2.7	4.3
December	1.7	3.0	4.7
2007			
January	1.8	2.9	4.7
February	1.4	2.6	4.0
March	1.6	3.1	4.7
April	1.6	2.9	4.5

Source: Petral Monthly Olefin Feedslate Survey

PROPYLENE FROM US STEAM CRACKERS

Table 3

	Production, million lb		
	LPG crackers	Multifeed crackers	Coproduct production
2006			
July	194.8	989.5	1,184.4
August	189.7	995.7	1,185.5
September	130.7	969.8	1,100.5
October	166.6	880.5	1,047.1
November	154.2	859.1	1,013.3
December	147.9	938.7	1,086.6
2007			
January	186.0	875.2	1,061.2
February	133.9	817.1	951.0
March	141.9	941.1	1,083.0
April	158.3	880.3	1,038.6

Source: Petral Monthly Propylene Supply Analysis

US REFINERY MERCHANT PROPYLENE

Table 4

	Sales, million lb			
	Texas	Louisiana	Other states	Total
2006				
July	546.3	469.1	392.6	1,408.0
August	509.8	400.6	396.2	1,306.7
September	469.6	502.7	383.5	1,355.8
October	475.1	517.1	386.6	1,378.8
November	422.0	497.6	402.8	1,322.4
December	555.7	541.4	397.9	1,494.9
2007				
January	533.4	494.5	392.6	1,420.4
February	389.7	420.9	241.4	1,052.0

Source: EIA Petroleum Supply Monthly

ary. Spot prices for BTX were 2.5-5.5% higher in March than in January.

The lag in spot prices for major coproducts was a significant factor in the divergence of ethylene production costs based on natural gasoline and similar light naphthas vs. production costs based on ethane. As a result, light naphthas became generally more expensive than ethane, especially during March.

The spike in motor gasoline prices continued during April and May; spot prices for natural gasoline-light naphthas and propane continued to diverge. During April and May, spot prices for natural gasoline increased an additional 14.3% and spot prices for light naphthas increased 13.3%. Spot prices for propane, however, increased only 8.9%.

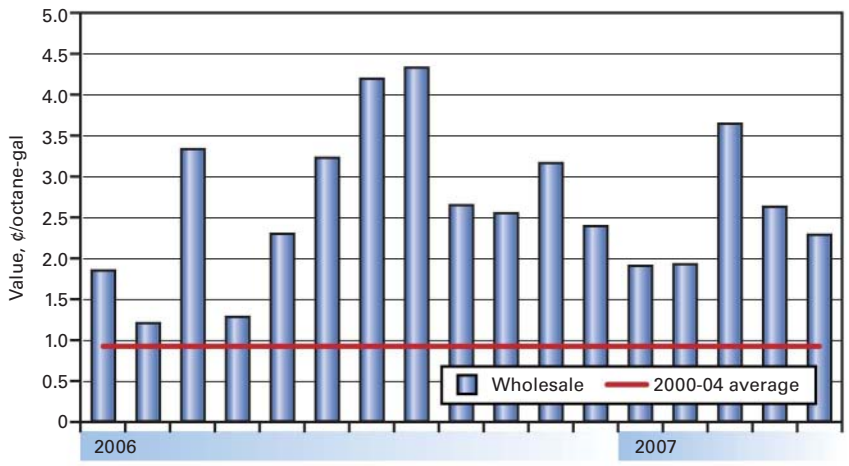
Spot prices for purity ethane increased 17.7% from March through May. Despite the jump in spot prices for ethane during April and May, variable ethylene production costs for ethane were consistently less than variable ethylene production costs for propane due to the lag in spot prices for propylene.

For ethylene producers that have the capability to market all coproducts at spot prices, however, variable ethylene production costs for ethane were 1-2¢/lb higher than for natural gasoline during April and May. For ethylene producers that market some or all of their coproducts at discounted prices, variable ethylene production costs for ethane were 6-8¢/lb lower than for natural gasoline during April and May.

Production costs for ethylene on the Houston Ship Channel (based on full spot prices for all coproducts) increased to 29-30¢/lb in March from 22-25¢/lb in January. Production costs for ethylene continued to escalate during April and May—the industry composite averaged 33-34¢/lb in May.

US GULF COAST OCTANE VALUES

Fig. 6



Source: Petral Analysis

ETHYLENE COSTS, HOUSTON SHIP CHANNEL

Table 5

	Variable, direct fixed cash costs, ¢/lb				
	Purity ethane	Purity propane	Normal butane	Natural gasoline	Industry composite
2006					
July	36.5	36.1	29.1	34.3	34.6
August	34.6	33.2	27.8	31.1	33.7
September	28.1	27.9	21.9	23.5	27.0
October	27.8	27.9	24.0	23.4	27.3
November	27.1	29.0	24.5	24.4	27.6
December	28.3	29.1	24.5	27.8	29.7
2007					
January	25.1	25.3	22.9	21.9	23.7
February	26.7	28.2	21.6	26.2	27.1
March	27.8	30.4	24.8	30.1	29.3
April	30.3	31.6	25.3	30.8	31.0
May	32.1	32.0	29.2	36.7	33.5
Forecast					
June	30.7	28.6	24.8	35.5	31.5
July	30.6	29.0	20.7	30.1	30.1
August	30.1	27.0	22.1	29.1	29.2
September	30.6	27.0	21.9	28.6	29.3

Source: Petral production cost analysis and forecasts

Production costs for natural gasoline jumped to almost 37¢/lb in May and were 7¢/lb higher than in March. The 20% increase in production was primarily due to rising feedstock prices resulting from the surge in spot prices for unleaded regular gasoline.

Table 5 shows trends in ethylene production costs.

Ethylene prices, profit margins

Contract prices for ethylene averaged 40¢/lb in first-quarter 2007 or 4.8¢/lb less than in fourth-quarter 2006. Contract prices increased to 41¢/lb in March from 39.5¢/lb in January and February. Contract prices increased again in April and stood at 44.5¢/lb at the beginning of May.

Contract prices for ethylene in April were about equal to the average for fourth-quarter 2006. The rebound in contract prices during March-May, however, was just barely sufficient to keep profit margins steady in the face of rising production costs. Margins based on contract prices averaged 9.5-10.0¢/lb during January-May.

During first-quarter 2007, spot prices for ethylene fluctuated in a range of 34-36¢/lb and averaged 35¢/lb, or 1¢/lb higher than in fourth-quarter 2006. The increase in spot ethylene prices during the first quarter did not keep pace with rising production costs.

Margins based on spot prices and average production costs narrowed to 3.4¢/lb in March from 7.1¢/lb in January. Furthermore, profit margins for naphthas, condensates, and gas oils narrowed to 1.8¢/lb in March from 8.6¢/lb in January.

Spot prices for ethylene increased to 38-39¢/lb in May, but margins based on average production costs remained at 4¢/lb. Margins for LPG feeds averaged 4.6¢/lb in April and May, but margins for naphthas, condensates, and gas oils (averaged) slipped to 2.4¢/lb in May from 3.6¢/lb in April.

Figs. 4 and 5 show historic trends in ethylene prices (spot and net transaction prices) and profit margins based on composite production costs.

Propylene economics, prices

Prices for all grades of propylene move in tandem with each other, and differentials between grades are generally constant within a narrow range. The premium for polymer-grade propylene covers operating costs and profit margins for the various merchant propane-propylene splitters in Texas and Louisiana.

Spot prices for polymer-grade propylene averaged 43.2¢/lb in first-quarter 2007, or 4.1¢/lb higher than in fourth-quarter 2006. Spot prices for both polymer-grade propylene and unleaded regular gasoline rallied during first-quarter 2007, but spot prices for polymer-grade propylene were sharply higher than for unleaded regular gasoline during January and February. The differential between polymer-grade propylene and unleaded regular gasoline therefore widened to 25.5¢/gal (based on converting polymer-grade propylene prices from ¢/lb to ¢/gal) from 14.9¢/gal during fourth-quarter 2006.

Spot prices for refinery-grade propylene rebounded in early January and averaged 40.0-40.5¢/gal during January and February. When spot prices for unleaded regular gasoline and alkylate

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began to increase during March-May, spot prices for refinery-grade propylene also moved higher, especially during April and May.

Spot prices for refinery-grade propylene averaged 41.1¢/lb in first-quarter 2007. Contract prices for refinery-grade propylene averaged 39.2¢/lb in first-quarter 2007.

After contracts settled for April, spot prices for refinery-grade propylene began to move steadily higher. By late April, spot prices averaged about 49¢/lb or 4.0-4.5¢/lb higher than in early April. Almost immediately after contracts settled for May, however, spot prices for refinery-grade propylene declined by about 5¢/lb.

The seasonal increase in refinery merchant propylene sales began to improve availability and prices fell about 4.5¢/lb within a few days after the contract for May settled at 48.25¢/lb. Based on data for the first three weeks of May, spot prices for refinery-grade propylene averaged 46.25-46.5¢/lb or 1.75-2.0¢/lb lower than the May contract price.

Polymer-grade propylene prices usually command a premium of 4-5¢/lb vs. refinery-grade propylene. During first-quarter 2007, the premium for polymer-grade propylene (contract price basis) was consistently 5.5¢/lb and remained at 5.5¢/lb in April but narrowed to 5.25¢/lb in May.

Octane values, propylene prices

We determine octane's incremental value using the differential between unleaded premium and unleaded regular gasoline prices divided by the difference in octane (87 octane for unleaded regular gasoline and 93 octane for unleaded premium gasoline).

During January and February, incremental octane values were steady and averaged 1.90-1.95¢/octane-gal vs. an average of 2.7¢/octane-gal in fourth-quarter 2006. The lull in octane values ended abruptly after early March. Incremental octane values jumped to 5.9¢/octane-gal in late March but then began to weaken. Octane values averaged 2.6¢/octane-gal in April and slipped to 2.3¢/octane-gal in May.

Fig. 6 shows historic trends in incremental octane values on the US Gulf Coast.

During first-quarter 2007, price differentials between refinery-grade propylene and spot alkylate were at their peak in January but declined during February-May. Spot prices for refinery-grade propylene averaged 12¢/lb more than for alkylate in January but only 5.3¢/lb in March. In May, the differential between refinery-grade propylene and alkylate narrowed to 2.5-2.75¢/lb.

Summer, fall 2007 outlook

Crude inventories in commercial storage increased during first-quarter 2007. Total inventories of 320-325 million bbl at the end of March were 16-20 million bbl higher than at yearend 2006. Furthermore, crude inventories continued to increase during April and May and reached 340-345 million bbl at the end of May. Crude inventories increased despite OPEC production curtailments.

The significant improvement in crude oil availability portends weaker prices for WTI during third-quarter 2007, if gasoline supplies continue to improve as they did during May.

Gasoline imports were consistently lower than year-earlier volumes during first-quarter 2007. Imports began to increase in April and continued to rise in May but also continued to lag year-earlier levels. Gasoline inventories therefore fell to unusually low levels in late April and remained about 15 million bbl lower than year-earlier levels at the end of May. While gasoline inventories continue to increase, however, the abnormally strong bullish pressures on motor gasoline prices will subside.

Refinery crude runs will increase to peak seasonal rates before the end of June and refinery gasoline production will increase to peak volumes during third-quarter 2007. If gasoline imports continue to increase and average 1.4-1.5 million b/d during June-September, total gasoline inventories will recover to parity vs. year-earlier levels by August.

When the gasoline market begins to recognize these improvements in the near-term outlook for the gasoline supply-demand balance, spot prices for gasoline will fall sharply from their abnormally high levels. Spot prices for unleaded regular on the US Gulf Coast are poised to decline 30-40¢/gal or more during June and July.

When the collapse in motor gasoline prices begins, the various bearish fundamental considerations for crude oil will emerge as the dominant influences on WTI prices. WTI prices will average $60-62/bbl during third-quarter 2007 and will decline to $57-59/bbl during fourth-quarter 2007.

The projected collapse in gasoline prices and the continued decline in octane values will also have a strongly bearish effect on spot prices for propylene and BTX. Spot prices for refinery-grade propylene will average 41-43¢/lb during third-quarter 2007 and 36-38¢/lb in fourth-quarter 2007. Despite these projected declines, refinery-grade pro-

The author

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pylene prices will average 6-8¢/lb more than spot alkylate during second-half 2007 vs. 4¢/lb in second-quarter 2007.

Prices for all feedstocks and coproducts will decline during second-half 2007, but spot prices for light naphthas and natural gasoline are likely to decline more than for ethane and propane. Composite production costs will therefore decline 3-5¢/lb during June and July. During third-quarter 2007, cash production costs will average 31-32¢/lb vs. about 36¢/lb in May. ✦

NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	Mar. 2006	Feb. 2007	Mar. 2007
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,744.4	1,829.5	1,833.3
Electrical machinery	189.5	394.7	516.9	513.6	520.2	510.5	526.8	516.8
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	960.7	969.5	969.5
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,119.2	1,246.9	1,251.4
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,179.4	1,179.4	1,374.7
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,102.8	1,150.4	1,189.2
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,228.4	1,335.2	1,388.7
Labor component	258.8	951.9	2,314.2	2,411.6	2,497.8	2,477.9	2,558.6	2,559.6
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	1,978.1	2,069.2	2,091.2

Refinery operating (1956 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	Mar. 2006	Feb. 2007	Mar. 2007
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,601.6	1,635.6	1,704.0
Labor cost	93.9	200.5	191.8	201.9	204.2	209.5	222.2	219.7
Wages	123.9	439.9	984.0	1,007.4	1,015.4	1,008.6	1,058.2	1,046.9
Productivity	131.8	226.3	513.3	501.1	497.5	481.5	476.2	476.5
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	732.6	763.5	771.7
Chemical costs	96.7	229.2	268.2	310.5	365.4	352.7	367.1	370.0
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	577.8	600.6	609.7
*Process units**	103.6	457.5	638.1	787.2	870.7	879.8	906.4	932.4

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, Journal Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

How Nelson-Farrar indexes of chemical costs have changed

Gary Farrar
Contributing Editor

The costs of two important chemicals used in crude refining changed very little during 2004-06, while the costs of three others varied significantly.

The two stable chemicals were hydrofluoric acid with an index constant of 414.9 and sulfuric acid with an index average of 397.4.

Sodium hydroxide ended with 644.9 in fourth-quarter 2006, rising from 529.6 in first-quarter 2004.

Platinum rose significantly to 1,466.4 in the last quarter of 2006 from 762.1 during first-quarter 2004. However, the average for 2004 was 762.1, while 1,344.4 was the average for 2006.

Sodium carbonate rose to 470.5 in fourth-quarter 2006 from 306.5 in first-quarter 2004.

During 2004-06, sodium carbonate averaged 310.3, 357.4, and 452.4 for the 3 years, respectively.

The Nelson-Farrar overall inorganic chemical index showed an increase throughout the period, varying to 714.2 in fourth-quarter 2006 from 492.6 in first-quarter 2004. ✦

NELSON-FARRAR INDEXES OF CHEMICAL COSTS

Year and quarter	Inorganic	Hydrofluoric acid	Sulfuric acid	Platinum	Sodium carbonate	Sodium hydroxide
2004						
1st	492.6	414.9	397.4	762.1	306.5	529.6
2nd	495.8	414.9	397.4	762.1	310.6	529.6
3rd	507.5	414.9	397.4	762.1	310.6	529.6
4th	523.6	414.9	397.4	762.1	313.6	529.6
Year	**504.9**	**414.9**	**397.4**	**762.1**	**310.3**	**529.6**
2005						
1st	545.8	414.9	397.4	762.1	319.5	529.6
2nd	555.9	414.9	397.4	762.1	358.5	529.6
3rd	565.1	414.9	397.4	762.1	366.3	529.6
4th	584.9	414.9	397.4	990.8	385.2	529.6
Year	**562.9**	**414.9**	**397.4**	**819.3**	**357.4**	**529.6**
2006						
1st	648.9	414.9	397.4	1,140.8	427.5	586.2
2nd	692.8	414.9	397.4	1,336.0	456.4	625.3
3rd	691.2	414.9	397.4	1,434.3	455.3	624.1
4th	714.2	414.9	397.4	1,466.4	470.5	644.9
Year	**686.8**	**414.9**	**397.4**	**1,344.4**	**452.4**	**620.1**

ITEMIZED REFINING COST INDEXES

The cost indexes may be used to convert prices at any date to prices at other dates by ratios to the cost indexes of the same date. Item indexes are published each quarter (first week issue of January, April, July, and October). In addition the Nelson Construction and Operating Cost Indexes are published in the first issue of each month of Oil and Gas Journal.

Operating cost (based on 1956 = 100.0):	1954	1972	2004	2005	2006	Feb. 2007	*References	Index for earlier year in Costimating and Questions on Technology issues
Power, industrial electrical	98.5	131.2	727.9	771.3	850.2	870.3	Code 0543	No. 13, May 19, 1958
Fuel, refinery price	85.5	152.0	944.5	1,288.9	1,523.6	1,556.6	OGJ	No. 4, Mar. 17, 1958
Gulf cargoes	85.0	130.4	1,250.7	1,635.4	2,023.9	1,526.9	OGJ	No. 4, Mar. 17, 1958
NY barges	82.6	169.6	1,130.7	1,539.6	1,837.5	1,500.4	OGJ	No. 4, Mar. 17, 1958
Chicago low sulfur	—	—	1,478.4	1,478.4	1,765.8	1,425.1	OGJ	July 7, 1975
Western US	84.3	168.1	1,427.7	1,941.5	2,358.1	2,045.6	OGJ	No. 4, Mar. 17, 1958
Central US	60.2	128.1	953.8	1,274.0	1,765.9	2,025.5	OGJ	No. 4, Mar. 17, 1958
Natural gas at wellhead	83.5	190.3	5,322.0	7,010.6	6,306.5	6,672.2	Code 531-10-1	No. 4, Mar. 17, 1958
Inorganic chemicals	96.0	123.1	504.9	562.9	686.8	706.5	Code 613	Oct. 5, 1964
Acid, hydrofluoric	95.5	144.4	414.9	414.9	414.9	414.9	Code 613-0222	Apr. 3, 1963
Acid, sulfuric	100.0	140.7	397.4	397.4	397.4	397.4	Code 613-0281	No. 94, May 15, 1961
Platinum	92.9	121.1	762.1	819.3	1,344.5	1,422.1	Code 1022-02-73	July 5, 1965, p. 117
Sodium carbonate	90.9	119.4	310.3	357.3	452.4	465.3	Code 613-01-03	No. 58, Oct. 12, 1959
Sodium hydroxide	95.5	136.2	529.6	529.6	620.1	637.9	Code 613-01-04	No. 94, May 15, 1961
Sodium phosphate	97.4	107.0	733.7	733.7	733.7	733.7	Code 613-0267	No. 58, Oct. 12, 1959
Organic chemicals	100.0	87.4	587.9	666.5	764.5	756.9	Code 614	Oct. 5, 1964
Furfural	94.5	137.5	848.1	961.9	1,103.1	1,092.5	Chemical Marketing Reporter	No. 58, Oct. 12, 1959
MEK, tank-car lots	82.6	87.5	408.3	625.0	625.0	625.0	Reporter	
Phenol	90.4	47.1	339.1	411.3	374.9	401.3	Code 614-0241	No. 58, Oct. 12, 1959

ITEMIZED REFINING COST INDEXES

Operating cost (based on 1956 = 100.0):	1954	1972	2004	2005	2006	Feb. 2007	*References	Index for earlier year in Costimating and Questions on Technology issues
Operating labor cost (1956 = 100)								
Wages & benefits	88.7	210.0	984.0	1,007.0	1,015.4	1,058.2	Employ & Earn	No. 41, Feb. 16, 1969
Productivity	97.2	197.0	513.3	501.1	497.5	476.2	Employ & Earn	No. 41, Feb. 16, 1969
Construction labor cost (1946 = 100)								
Skilled const.	174.6	499.9	2,077.2	2,170.8	2,240.7	2,300.0	Eng. News Record	No. 55, Nov. 3, 1949
Common labor	192.1	630.6	2,747.1	2,863.5	2,971.7	3,038.7	Eng. News Record	No. 55, Nov. 3, 1949
Refinery cost	183.3	545.9	2,314.2	2,411.6	2,497.8	2,558.6	OGJ	May 15, 1967
Equipment or materials (1946 = 100):								
Bubble tray	161.4	324.4	1,329.6	1,409.4	1,484.0	1,537.8	Computed	July 8, 1962, p. 113
Building materials (nonmetallic)	143.6	212.4	825.9	886.4	969.6	999.4	Code 13	No. 61, Dec. 15, 1949
Brick—building	144.7	252.5	1,215.8	1,301.7	1,408.6	1,434.0	Code 1342	No. 20, Mar. 3, 1949
Brick—fireclay	193.1	322.8	1,358.6	1,441.1	1,540.5	1,603.9	Code 135	May 30, 1955
Castings, iron	188.1	274.9	1,192.5	1,290.0	1,351.3	1,377.4	Code 1015	Apr. 1, 1963
Clay products (structural, etc.)	159.1	342.0	843.9	893.8	951.6	957.7	Code 134	No. 20, Mar. 3, 1949
Concrete ingredients	141.1	218.4	908.3	985.5	1,092.0	1,150.0	Code 132	No. 22, March 17, 1949
Concrete products	138.5	199.6	761.9	841.3	921.1	953.2	Code 133	Oct. 2, 1967, p. 112
Electrical machinery	159.9	216.3	516.9	513.6	520.2	526.8	Code 117	May 2, 1955
Motors and generators	157.7	211.0	796.8	839.2	880.3	901.5	Code 1173	May 2, 1955
Switchgear	171.2	271.0	1,045.9	1,090.0	1,147.3	1,192.3	Code 1175	May 2, 1955
Transformers	161.9	149.3	486.0	537.1	612.5	676.3	Code 1174	No. 31, May 19, 1949
Engines (combustion)	150.5	233.3	919.4	931.1	959.7	969.5	Code 1194	No. 36, June 23, 1949
Exchangers (composite)	171.7	274.3	863.8	1,072.3	1,162.7	1,179.4	Manufacturer	Mar. 16, 1964
Copper base	190.7	266.7	816.2	992.1	1,059.4	1,081.8	Manufacturer	Mar. 16, 1964
Carbon steel	156.8	281.9	866.1	1,080.2	1,162.1	1,189.4	Manufacturer	Mar. 16, 1964
Stainless steel (304)	—	—	914.3	1,119.3	1,174.8	1,193.3	Manufacturer	July 1, 1991
Fractionating towers	151.0	278.5	1,065.1	1,157.2	1,207.2	1,245.5	Computed	June 8, 1963, p. 133
Hand tools	173.8	346.5	1,651.7	1,722.1	1,792.5	1,823.0	Code 1042	June 27, 1955
Instruments (composite)	154.6	328.4	1,087.6	1,108.0	1,166.0	1,246.9	Computed	No. 34, June 9, 1949
Insulation (composite)	198.5	272.4	2,230.4	2,228.6	2,257.4	2,288.4	Manufacturer	July 4, 1988, p. 193
Lumber (composite):	197.8	353.4	1,417.9	1,359.6	1,309.8	1,227.1	Code 81	No. 7, Dec. 2, 1948
Southern pine	181.2	303.9	1,040.7	998.6	984.3	869.3	Code 81102	No. 7, Dec. 2, 1948
Redwood, all heart	238.0	310.6	2,145.1	2,057.9	1,948.1	1,791.5	Code 811-0332	July 5, 1965, p. 117
Machinery								
General purpose	159.9	278.5	1,106.7	1,163.6	1,213.7	1,256.6	Code 114	Feb. 17, 1949
Construction	165.9	324.4	1,407.3	1,499.2	1,559.7	1,586.1	Code 112	Apr. 1, 1968, p. 184
Oil field	161.9	269.1	1,333.0	1,454.8	1,599.1	1,697.0	Code 1191	Oct. 10, 1955
Paints—prepared	159.0	231.8	907.4	975.3	1,040.8	1,063.8	Code 621	May 16, 1955
Pipe								
Gray iron pressure	195.0	346.9	2,301.2	2,580.2	2,687.9	2,689.5	Code 1015-0239	Jan. 3, 1983
Standard carbon	182.7	319.9	1,900.0	2,217.3	2,306.9	2,311.1	Code 1017-0611	Jan. 3, 1983
Pumps, compressors, etc.	166.5	337.5	1,581.5	1,685.5	1,758.2	1,829.5	Code 1141	No. 29, May 5, 1949
Steel-mill products	187.1	330.6	1,300.6	1,409.1	1,527.5	1,604.3	Code 1017	Jan. 3, 1983
Alloy bars	198.7	349.4	1,050.1	1,146.8	1,311.8	1,212.0	Code 1017-0831	Apr. 1, 1963
Cold-rolled sheets	187.0	365.5	1,278.4	1,462.5	1,658.4	2,086.6	Code 1017-0711	Jan. 3, 1983
Alloy sheets	177.0	225.9	665.0	760.3	862.4	1,084.9	Code 1017-0733	Jan. 3, 1983
Stainless strip	169.0	221.2	710.0	811.6	920.7	1,158.6	Code 1017-0755	Jan. 3, 1983
Structural carbon, plates	193.4	386.7	1,493.7	1,654.5	1,766.6	1,829.6	Code 1017-0400	Jan. 3, 1983
Welded carbon tubing	180.0	265.5	1,925.0	2,246.8	2,337.3	2,341.3	Code 1017-0622	Jan. 3, 1983
Tanks and pressure vessels	147.3	246.4	868.7	974.4	1,014.3	1,045.3	Code 1072	No. 5, Nov. 18, 1949
Tube stills	123.0	125.3	503.5	540.5	579.9	605.2	Computed	Oct. 1, 1962
Valves and fittings	197.0	350.9	1,660.6	1,738.2	1,839.6	1,905.5	Code 1149	No. 46, Sept. 1, 1940
Nelson-Farrar Refinery (Inflation Index)								
(1946)	179.8	438.5	1,833.6	1,918.8	2,008.1	2,069.2	OGJ	May 15, 1969
Nelson-Farrar Refinery Operation								
(1956)	88.7	118.5	486.7	542.1	579.0	600.6	OGJ	No. 2, Mar. 3, 1958
Nelson-Farrar Refinery Process								
(1956)	88.4	147.0	638.1	787.2	870.7	906.4	OGJ	No. 2, Mar. 3, 1958

*Code refers to the index number of the Bureau of Statistics, US Department of Labor, "Wholesale Prices" Itemized Cost Indexes, Oil & Gas Journal.

US NATURAL GAS—
Conclusion

Rockies Express faces downstream bottlenecks

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Jim Simpson
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Golden, Colo.

Kinder Morgan's Rockies Express Pipeline needs capacity downstream from its Clarington, Ohio, terminus to expand before it can fully address growing demand in the Northeast. The availability of new takeaway capacity from projects such as those announced by Tennessee Gas and TETCO will be a key factor determining whether REX will serve Northeast demand with incremental supply or will simply displace gulf coast supplies currently serving that market.

REX's capacity constraints at the east end of the system and their eventual resolution will add to the uncertainty surrounding flow displacements, supply-demand shifts, and regional pricing adjustments brought about by REX. Rockies prices will rise significantly relative to other producing basins. If the east end of REX is constrained, additional demand does not emerge to mitigate the displacement of supplies back into the gulf, and if net incremental production continues to add to gulf supplies, it is not unreasonable to expect that Rockies prices could even trade at a premium to gulf prices.

The first article of this series examined the background of the REX pipeline project and analyzed the effect on US natural gas markets of REX Phases I and II.

This concluding article will detail the market shifts expected as a result of the combination of REX Phase III's completion and downstream capacity constraints.

Capacity bottlenecks

Capacity of the receiving pipelines will profoundly affect Rockies Express Pipeline Phase IIIa flows. At Lebanon, Ohio, constraints will limit the ability of customers east of REX to obtain incremental supplies from it without displacing gas from other areas. The extension to Clarington in Phase IIIb will provide access to available capacity on Dominion Transmission, TETCO, and Tennessee Gas Pipeline, but constraints east of Clarington, in Pennsylvania, New York, and New Jersey will limit shippers' ability to use REX as an incremental supply source on peak days, particularly during the winter months.

Lebanon

When Phase IIIa is operational, shippers will be able to deliver 1.8 bcfd to Lebanon (Fig. 1). Vectren and Cincinnati Gas & Electric will be able to receive gas directly from REX. Unless they have incremental demand, however, a reduction in receipts from one or more of these companies' traditional suppliers must offset receipts from REX.

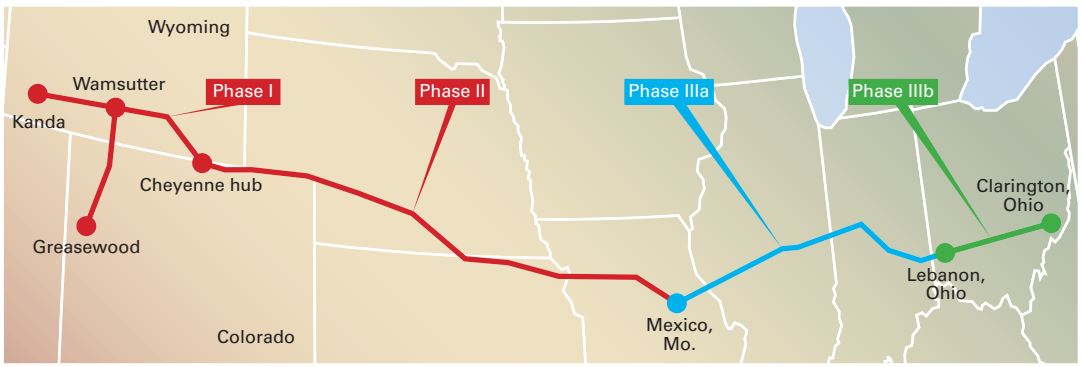
Fig. 2 shows that Columbia Gas Transmission and Dominion are already constrained at Lebanon, particularly during heating season.

Dominion had available capacity during the 2006-07 heating season because of warm weather in December and early January and high levels of gas in storage. For these reasons, Dominion needed less gas from nonlocal supply areas.

Affiliated local distribution companies act as primary markets

ROCKIES EXPRESS PIPELINE

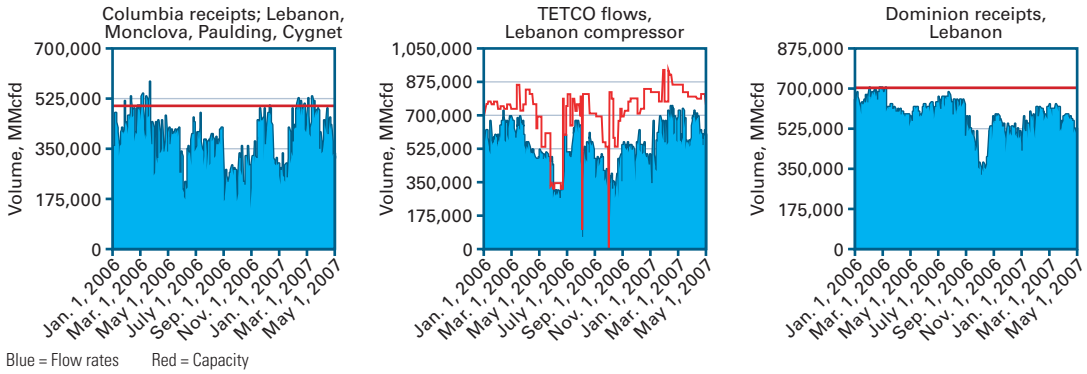
Fig. 1



for both Columbia and Dominion. Flow data suggest that Columbia Gas of Ohio has experienced a roughly 10%/year (25 MMcfd) decline in sales and transport volumes since 2004. Dominion-affiliated East Ohio Gas, experienced similar declines in 2006 compared to 2005 (19 MMcfd).

LEBANON, AVAILABLE CAPACITY

Fig. 2



Rising Appalachian production may have offset some of the decline, but some appears to be due to declining demand. Either way, without increased demand from Dominion or Columbia's affiliated utilities, incremental volumes received by these pipelines at Lebanon must flow through either to storage facilities or customers east of Clarington.

TETCO-Clarington

Pipeline capacity east of Clarington is similarly constrained. Fig. 3 illustrates TETCO's situation.

TETCO has two lines in Ohio: the Lebanon line and the mainline. The Lebanon line originates in East Texas and gains capacity and supply at Lebanon. It flows through the Sarahsville compressor and then turns south where it connects with the mainline. The mainline originates in South Texas and Louisiana, runs north through Kentucky, through the Athens compressor and then merges with the Lebanon line before moving east toward the Holbrook compressor located in western Pennsylvania.

The Lebanon line is significantly smaller than the mainline. Capacity at Sarahsville, for example, is about 750 MMcfd compared to about 2 bcfd for the mainline.

REX interconnects with the Lebanon line just east of Sarahsville. Capacity utilization at Sarahsville averaged 74% in 2006. It was more than 90% full for 108 days and more than 95% full for 66 days, leaving little unused capacity, particularly on a peak day in winter.

Capacity exists on the mainline and east of Holbrook. REX volumes, however, cannot enter that part of the TETCO system without first entering the constrained Lebanon line.

TETCO is currently undertaking its Time II expansion project (approved by FERC June 8, 2007), which will increase the capacity of the Lebanon line by 150 MMcfd beginning later this year. This project entails looping and replacement of existing pipeline on the Lebanon line and the southern branch of the mainline east of Holbrook.

The Time II expansion will enable incremental REX volumes to move past Holbrook to Pennsylvania, New York, and New Jersey customers, as well as to many of the storage facilities accessed by TETCO in Pennsylvania and Maryland. The expansion will not, however, significantly affect TETCO shippers' ability to move gas east from storage facilities to their markets on peak days. These constraints will continue to limit incremental volumes from reaching East Coast markets.

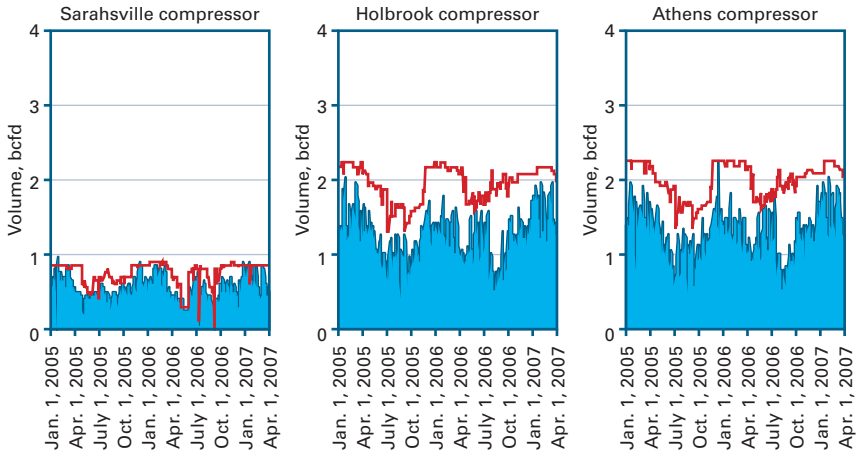
TGP-Clarington

A similar situation exists on Tennessee Gas Pipeline. Fig. 4 shows capacity utilization at Compressor Station 219 in western Pennsylvania. REX interconnects with Tennessee Gas southwest of Station 219. Flows over the past 2 years show that Tennessee Gas has significant unused capacity and could receive incremental volumes from REX. In the summer, such volumes presumably would be used either by power generators or to fill storage, increasing the storage fill rate.

As was the case with TETCO, however, capacity constraints east of Pennsylvania and New York pose a significant

TETCO, EAST OF CLARINGTON; AVAILABLE CAPACITY

Fig. 3



Blue = Flow rates Red = Capacity

impediment to shippers who want to bring incremental volumes to markets in Tennessee. Flows through Tennessee Gas either east of the storage facilities on the southern line or east of the interconnection points where Canadian gas enters the system at Niagara are constrained during peak load periods.

Canadian imports have been declining at Niagara and other Northeast locations over the past few years but remain an integral part of Tennessee Gas shippers' current supply portfolio. Curtailments occur at Stations 245 and 321 (Fig. 4). Incremental REX volumes will allow Tennessee Gas to fill storage more rapidly and may also offset declining Canadian supplies, but these capacity constraints will limit their ability to do so.

Tennessee Gas announced an expansion of its pipeline in New York to improve deliverability to East Coast markets. The expansion entails construction of a high-pressure pipeline originating near Clarington and extending eastward to an interconnect with Iroquois Pipeline near Poughkeepsie, NY. The proposed line will have 1-1.5 bcfd capacity and is to be in service 2010-11. If constructed, the expansion will significantly improve the full deliverability potential of REX to customers in the highly constrained East Coast market.

REX advantage

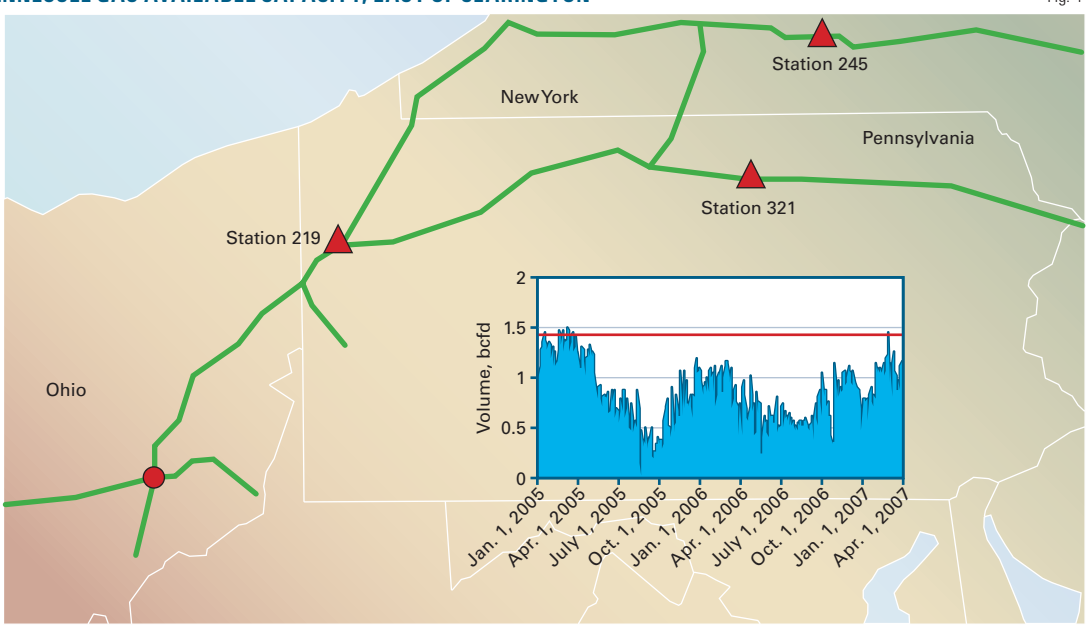
The REX project can operate at a maximum allowable operating pressure (MAOP) of up to 1,480 psig, as compared to 600-1,050 psig for TETCO, 450-790 psig for Tennessee Gas, and similar pressures for the other interconnected pipelines. This advantage translates to lower charges for fuel and lost and unaccounted for gas in the REX tariff. The implications of this advantage become apparent when comparing the delivered price incurred by shippers when moving gas to either Lebanon or Clarington.

The variable components of each pipeline's tariff—commodity charge, plus fuel and loss—provide the basis for evaluation of market economics. The much larger demand component of the tariff must be paid regardless of whether the shipper moves a molecule of gas.

Transportation alternatives that influence shipper behavior and market pricing hinge solely on the variable cost associated with alternative movements of natural gas, for the purposes of this article, which uses fuel charges for REX as reported in its "Fuel Guidance" dated Sept. 11, 2006. Original capacity holders

TENNESSEE GAS AVAILABLE CAPACITY, EAST OF CLARINGTON

Fig. 4

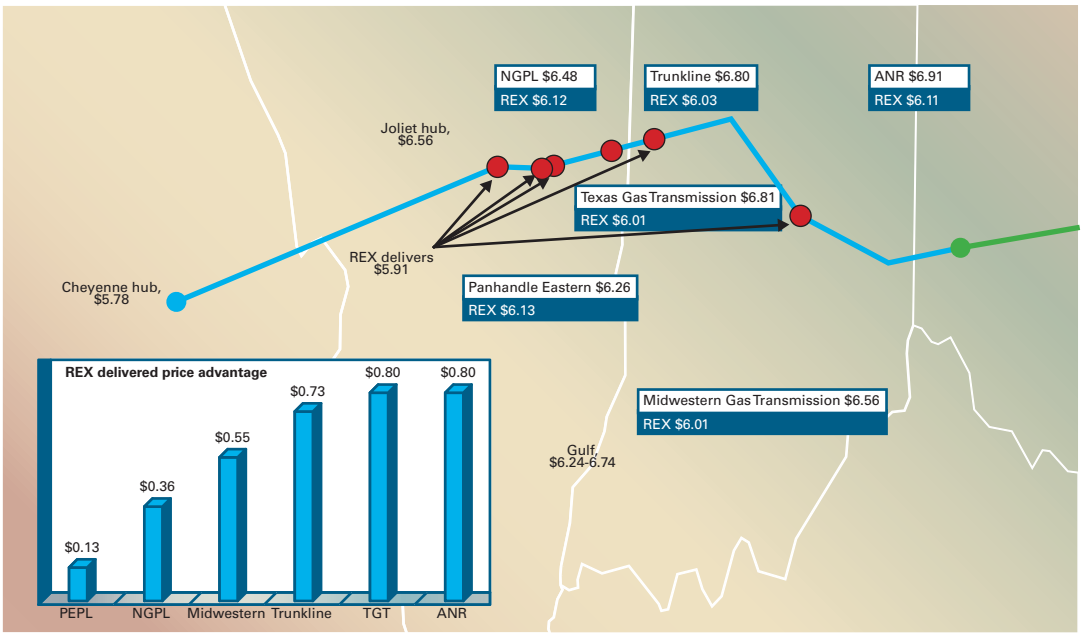


Blue = Flow rates Red = Capacity

on REX have contractual fuel rates lower than used here and will thus derive an even greater advantage than shown in this analysis.

A similar scenario holds true for shippers on competing pipelines. To the extent such shippers enjoy discounted prices, transportation economics will differ from the following analysis.

DELIVERED PRICES, PHASE IIIa INTERCONNECTS, 2006 AVERAGE COSTS Fig. 5



Tariff comparison

When REX East opens, REX shippers will have a dramatic price advantage to Lebanon over traditional supply areas, primarily because of the commodity cost differential. Fig. 5 shows the advantage by comparing the delivered price to Lebanon using REX to the current pipeline alternatives, defining commodity costs as the average 2006 price for the appropriate supply point.

The average 2006 price of $5.78 at Cheyenne serves as a proxy for REX. With one exception, competitive pipeline prices use the 2006 average price at the appropriate gulf supply point. Midwestern Gas Transmission commodity prices use the average 2006 price at Joliet. Price comparison demonstrates that REX shippers are able to purchase gas at a $0.50-1.00/MMbtu discount to alternative supply sources. Customers purchasing supply from REX suppliers that can use Opal or another producing area price point that historically trades at an additional $0.10-0.30/MMbtu discount to Cheyenne can gain an additional advantage.

The 2007 supply build up in the Rockies has so far greatly exaggerated Rockies price differentials. In April 2007 Cheyenne and Opal prices averaged $3.02/MMbtu less than Henry Hub prices.

This price advantage, coupled with the fuel-loss percent advantage, yields significantly lower-priced supply at Lebanon. Fig. 5 shows the advantage ranging from $0.13/MMbtu on Panhandle Eastern to $0.80/MMbtu on Texas Gas Transmission and ANR's Southeast leg. This advantage will initially force spot prices to decline in the gulf and East Texas supply areas relative to Cheyenne, Opal, and other Rockies production pricing points.

REX IIIa will cause a significant readjustment in prices, with Rockies prices rising sharply relative to gulf areas prices.

Once prices adjust after REX IIIa enters service, the differential between Cheyenne and the gulf and Cheyenne and Joliet should settle at about $0.10-0.20/MMbtu.

Assuming gas prices across supply areas equal to $7.00/MMbtu at the relevant purchase points, further demonstrates the relative economics of REX. This is not a price forecast but instead highlights the differences in gas transportation economics.

Assuming commodity-price differences that settle to reflect variable transportation differentials, Fig. 6 shows current differentials narrowing substantially, settling with gulf prices about $0.20 higher than Rockies prices, approximating the variable cost differential between the pipelines. This transition, however, will occur between December 2008 when REX IIIa commences service and July 2008 when REX IIIb becomes operational.

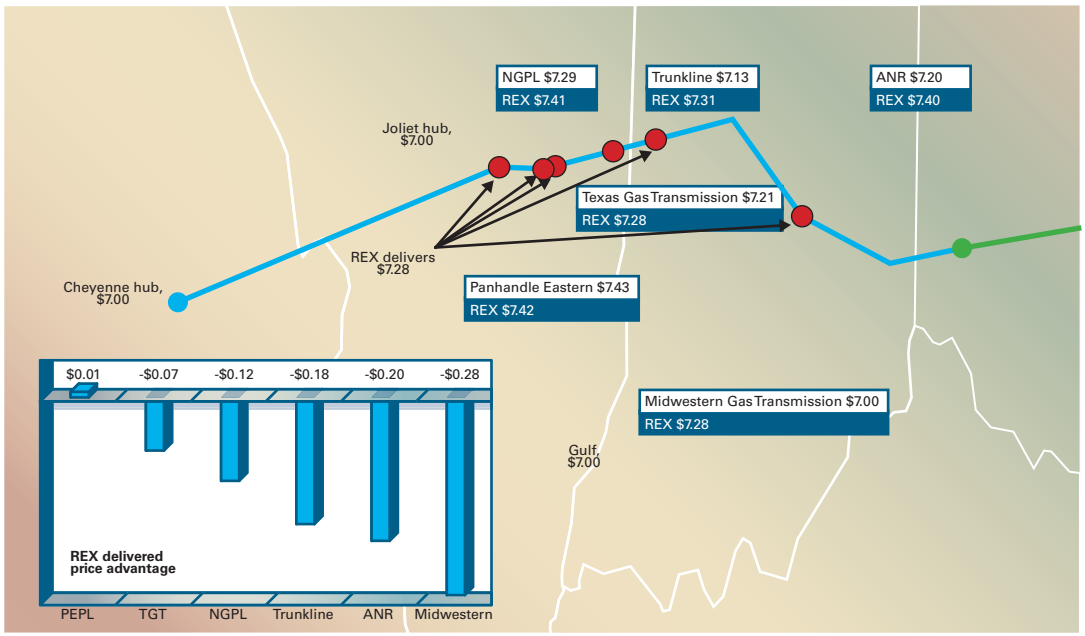
Reaching Clarington maximizes the REX market advantage. Rockies producers received an average of $0.52-0.91 less for their production than did gulf-area producers in 2006. This differential is substantially larger in 2007 and, coupled with the lower fuel charges associated with REX, translates into a $0.80-1.17/MMbtu delivered price advantage for REX shippers over shippers purchasing supplies from the traditional gulf areas.

Assuming that REX's commodity cost advantages continue through 2008, REX volumes should displace gulf volumes once REX reaches Clarington.

REX's price advantage at Clarington will drive relative prices down in the gulf and raise relative Rockies prices at

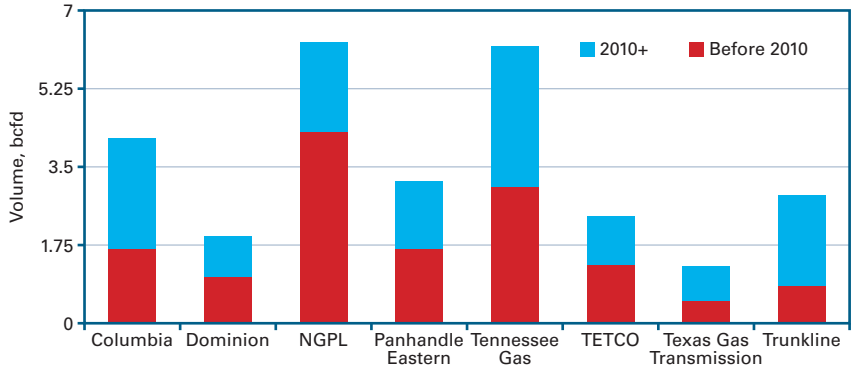
DELIVERED PRICES, PHASE IIIa INTERCONNECTS, EQUAL COMMODITY COSTS

Fig. 6



EXPIRING TRANSPORT CONTRACTS

Fig. 7



Cheyenne and Opal.

Again using a $7.00/MMbtu supply-area reference case, in which spot prices at Cheyenne and the gulf are equal, REX supplies hold an advantage over Tennessee Gas and TETCO and will be only slightly more expensive than supplies shipped to the region via Columbia Gulf. If the Rockies-to-gulf price spread settled equal to the variable transport differential, Rockies gas might hold as much as a $0.42 premium over some gulf supply points on TETCO and slightly less on Tennessee Gas.

Other factors will likely intervene to reduce or eliminate some of the Rockies premium, but the data clearly show that REX will go a long way toward allowing Rockies gas to trade at or near parity with gulf supplies.

REX market pressures will not occur in a vacuum. Other factors will affect the market while REX is being built. Production increases in the East Texas, Fort Worth, Arkoma, and Arkla basins will put gulf supplies under pressure. Increases in Northeast power generation demand could absorb some incremental supplies given new pipeline capacity east of Clarington to deliver REX supplies to the new markets. Lower Canadian imports could also make room for additional REX supplies. Each of these developments could buffet regional supply-demand balances as the REX realignment rolls through the market.

Canadian decline

Lower Canadian import volumes could make room for REX gas. Canadian gas is a significant component of Dominion and Tennessee Gas shippers' supply portfolios and also makes up a large portion of the overall supply portfolios of customers in the upper Midwest.

Imports into the Northeast declined by 157 MMcfd, or 6%, in 2006, and in the Midwest imports declined by 193 MMcfd, or 5%. Three factors led to the declines: falling production in Alberta, increased use of natural gas for the production of bitumen (oil sands), and growing need for gas as a generation fuel for new power facilities. All of these factors increase the demand for Rockies gas.

Supply build

The sharp buildup of new production in the gulf region has compounded the need for gas from the area to find a new market. Exploration and development success in the Barnett Shale, Woodford Shale and other relatively new production areas in East Texas, the Fort Worth, Arkoma, and Arkla basins has resulted in strong incremental production gains.

During the next 2 years, several new Gulf of Mexico projects, such as Anadarko's Independence Hub, are scheduled to come online and could in-

crease production by more than 1 bcfd.

These projects will cause incremental production in the region to swell for at least a few years. If production gains continue to accelerate even slightly, production from the region will be more than 1 bcfd higher by the end of 2008, when REX East comes online.

Demand growth

At the same time supply is building, demand is also growing. Bentek's demand forecast through 2010, which closely matches the most recent US Energy Information Administration forecast, calls for growth in the Upper Midwest, Northeast, Texas-Louisiana, and Southeast market areas, almost entirely based on increased power-generation demand. Aggregate demand from the four regions will have grown 3.9 bcfd, a 2.3%/year compound growth rate, by 2010. The Texas-Louisiana-Arkansas and Southeast regions show the highest incremental demand, 1.3 bcfd and 1.1 bcfd, respectively, but demand in the Upper Midwest and Northeast regions will grow as well, by a 0.7 bcfd and 0.8 bcfd, respectively.

Much of the gulf supply build will supply this growing demand. CenterPoint Energy's recently completed Carthage-to-Perryville pipeline and other pipelines under development will improve producers' ability to deliver supplies to the higher demand-growth areas. Similarly, gulf, East Texas, and other Midcontinent supplies will be able to use ANR, NGPL, Trunkline, and Texas Gas Transmission to increase flows to the Upper Midwest.

LNG wild card

LNG could add significantly to the gulf supply build. Lake Charles already has the potential to deliver more than 2.0 bcfd on a peak day and 1.8 bcfd on a sustained basis. Four new gulf coast LNG regasification plants—Sabine Pass, Freeport, Golden Pass, and Cameron—are set to come online in 2008 or 2009, bringing an aggregate 7.6 bcfd of incremental supply to the region.

Global competition for LNG supply among Europe, Asia, and the US, will likely lead to low load factors at these new US terminals, but a substantial amount of LNG could arrive during the shoulder and summer months. Asia and Europe have inadequate storage to pull demand for storage injection, resulting in a high likelihood that summer and shoulder-month prices in the US will be more attractive to global LNG suppliers.

Recontracting capacity

A large number of firm transportation contracts on multiple interstate pipelines will expire between 2007 and 2010. Fig. 7 shows the percentage of volume covered by those expiring contracts on pipelines that interconnect with REX (based on analysis of the January 2007 Index of Customer filings at FERC).

Across the pipelines shown, an average of 50% of firm contract volume will expire before 2010. NGPL has the largest percentage of firm transport contracts expiring (69%), but because of the competitive tariff economics it will probably be the least affected by REX. On the other hand, TETCO, Tennessee Gas, and Panhandle, the three pipelines which may be at the greatest competitive disadvantage, have 56%, 50%, and 55%, respectively, of their firm contracts expiring for before 2010.

The expiry of so much of the contracted firm transport volume between now and commencement of service on REX East suggests that many East Coast and Midwest utilities and end users (the primary capacity holders on the affected pipelines) will have the opportunity to realign their supply portfolios. ✦

New service provides drilling information

NeoDriller, a new online service, provides up-to-date oil and gas well drilling information on a global basis. Company staff, partners, and service providers can keep each other informed via their own private databases and company web sites at all times, regardless of location.

The service promises to be economical, easy to use, and it features bank-level security that encrypts and protects all information. The collection of data entry tools automatically generates reports.

The company provides a secure online storage facility for all electronic information generated during the drilling process from spud to flow. Archived daily, with off-site long-term storage, this firm stores and manages all data and files, delivering instant access via each client's web site.

OperationsMaster Plus bundled with OperationsMaster service provides operators with management of all aspects of a well's life cycle, the company notes.

All services are accessible via web pages. Additionally, each client's site is customized with their own look and feel. During the installation process, the client's current corporate look and existing spreadsheets are matched to ensure the service matches each client's current business processes.

Source: **NeoFirma Inc.**, 8117 Preston Rd., Suite 260, Dallas, TX 75225.

Updated seismic-to-simulation software

Newly released Petrel 2007.1 seismic-to-simulation software includes new functionality for all disciplines in the exploration and development work flow.

It promises productivity for geoscientists and engineers, collaboration from the field to office and back, and a shared understanding of risk and uncertainty enabling better decisions, in less time, the company says.

New seismic performance and scalability in Petrel 2007.1 help improve the productivity of exploration teams to deliver more high quality prospects, faster. Tighter integration of reservoir engineering work flows introduces simulation earlier, helping predict reservoir performance. Real-time data connections, from the rig to the office, help increase operational accuracy for better drilling performance and risk management.

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Source: **Schlumberger Ltd.**, 5599 San Felipe, Houston, TX 77056.

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[1] *Signet Readership Survey (February 2007)*

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	6-22 2007	[1]6-15 2007	6-22 2007	[1]6-15 2007	6-22 2007	[1]6-15 2007	6-23 2006
	1,000 b/d						
Total motor gasoline	380	395	12	15	392	410	525
Mo. gas. blending comp.	660	859	166	45	826	904	682
Distillate[2]	143	154	27	30	170	184	300
Residual	306	209	78	21	384	230	275
Jet fuel-kerosine	79	151	143	87	222	238	156
LPG	352	271	2	3	354	274	268
Unfinished oils	510	525	94	23	604	548	372
Other	523	356	—	—	523	356	540
Total products	**2,953**	**2,920**	**522**	**224**	**3,475**	**3,144**	**3,118**
Canadian crude	1,681	1,367	160	215	1,841	1,582	1,628
Other foreign	7,493	7,940	834	1,227	8,327	9,167	9,109
Total crude	**9,174**	**9,307**	**994**	**1,442**	**10,168**	**10,749**	**10,737**
Total imports	**12,127**	**12,227**	**1,516**	**1,666**	**13,643**	**13,893**	**13,855**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

PURVIN & GERTZ LNG NETBACKS—JUNE 22, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMBtu					
Barcelona	6.17	4.21	5.40	4.11	4.77	5.37
Everett	6.05	4.12	5.68	4.22	4.62	6.34
Isle of Grain	2.14	0.47	1.58	0.40	0.89	1.66
Lake Charles	4.74	2.99	4.51	3.15	3.40	5.32
Sodegaura	4.76	6.69	4.97	6.53	5.89	4.26
Zeebrugge	5.42	3.66	4.88	3.60	4.11	4.89

Definitions, see OGJ Apr. 9, 2007, p. 57. Source: Purvin & Gertz Inc. Data available in OGJ Online Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OGJ CRACK SPREAD

	*6-22-07	*6-23-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	90.05	81.59	8.46	10.4
Brent crude	72.18	68.03	4.15	6.1
Crack spread	17.87	13.57	4.30	31.7
FUTURES MARKET PRICES				
One month				
Product value	90.88	84.46	6.42	7.6
Light sweet crude	68.83	69.99	–1.16	–1.7
Crack spread	22.05	14.47	7.58	52.4
Six month				
Product value	84.46	81.69	2.76	3.4
Light sweet crude	71.24	72.26	–1.02	–1.4
Crack spread	13.22	9.44	3.78	40.0

*Average for week ending.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel Kerosine	Fuel oils		Unfinished oils
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PAD I	14,536	48,595	22,705	11,864	43,515	15,660	8,143
PAD II	71,492	49,737	16,110	6,427	29,441	1,254	12,507
PAD III	192,988	64,966	27,618	12,389	31,969	12,360	43,848
PAD IV	14,177	6,343	1,995	545	3,400	312	3,192
PAD V	[1]57,844	31,428	21,219	8,691	13,160	5,954	20,280
June 22, 2007	**[1]351,037**	**201,069**	**89,647**	**39,916**	**121,485**	**35,540**	**87,970**
June 15, 2007[3]	**348,622**	**206,336**	**91,493**	**39,971**	**123,170**	**36,561**	**88,346**
June 23, 2006	**342,800**	**210,398**	**91,018**	**39,290**	**126,596**	**41,573**	**94,808**

[1]Included in total motor gasoline. [2]Includes 6.185 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—JUNE 22, 2007

District	REFINERY OPERATIONS					REFINERY OUTPUT			
	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	3,539	1,375	1,408	1,618	87.0	1,839	104	423	101
App. Dist. 1	142	95	95	95	100.0	43	0	51	0
Dist. 1 total	**3,681**	**1,470**	**1,503**	**1,713**	**87.7**	**1,882**	**104**	**474**	**101**
Ind., Ill., Ky.	2,225	2,120	2,163	2,355	91.9	1,329	116	560	40
Minn., Wis., Dak.	415	408	413	442	93.4	303	32	111	11
Okla., Kan., Mo.	893	657	683	786	86.9	469	18	278	5
Dist. 2 total	**3,533**	**3,185**	**3,259**	**3,583**	**91.0**	**2,101**	**166**	**949**	**56**
Inland Texas	764	418	440	647	68.0	383	21	155	7
Texas Gulf Coast	3,864	3,193	3,300	4,031	81.9	1,457	307	832	111
La. Gulf Coast	3,427	3,286	3,290	3,264	100.8	1,329	358	793	108
N. La. and Ark.	226	179	189	215	87.9	110	9	46	2
New Mexico	167	109	109	113	96.5	150	3	38	7
Dist. 3 total	**8,448**	**7,185**	**7,328**	**8,270**	**88.6**	**3,429**	**698**	**1,864**	**235**
Dist. 4 total	**731**	**584**	**584**	**596**	**98.0**	**304**	**28**	**171**	**13**
Dist. 5 total	**2,903**	**2,443**	**2,717**	**3,173**	**85.6**	**1,764**	**416**	**548**	**145**
June 22, 2007	**19,296**	**14,867**	**15,391**	**17,335**	**88.8**	**9,480**	**1,412**	**4,006**	**550**
June 15, 2007*	**19,077**	**14,542**	**15,010**	**17,335**	**86.6**	**9,325**	**1,392**	**4,004**	**566**
June 23, 2006	**18,443**	**15,946**	**16,338**	**17,115**	**95.5**	**9,243**	**1,428**	**4,152**	**569**

*Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 6-20-07	Pump price* 6-20-07	Pump price 6-21-06
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	269.7	309.4	285.8
Baltimore	265.5	307.4	293.3
Boston	253.7	295.6	287.4
Buffalo	249.3	309.4	294.6
Miami	260.9	311.2	298.5
Newark	258.5	291.4	284.8
New York	246.7	306.8	295.9
Norfolk	260.7	298.3	287.6
Philadelphia	262.7	313.4	300.8
Pittsburgh	249.7	300.4	283.5
Wash., DC	267.6	306.0	305.4
PAD I avg.	258.6	304.5	292.5
Chicago	287.0	337.9	317.1
Cleveland	242.0	288.4	277.3
Des Moines	274.4	314.8	264.8
Detroit	277.6	326.3	280.8
Indianapolis	272.2	317.2	274.6
Kansas City	278.8	314.8	264.8
Louisville	281.0	317.9	282.7
Memphis	264.9	304.7	276.1
Milwaukee	269.3	320.6	282.6
Minn.-St. Paul	249.4	289.8	273.7
Oklahoma City	265.1	300.5	257.4
Omaha	253.1	299.5	271.3
St. Louis	275.8	311.8	258.6
Tulsa	264.0	299.4	255.5
Wichita	263.0	307.3	263.7
PAD II avg.	267.9	310.1	273.4
Albuquerque	284.3	320.7	278.8
Birmingham	261.3	300.0	272.9
Dallas-Fort Worth	253.1	291.5	282.7
Houston	248.7	287.1	282.2
Little Rock	259.6	299.8	270.8
New Orleans	267.3	305.7	276.0
San Antonio	252.9	291.3	266.8
PAD III avg.	261.0	299.4	275.7
Cheyenne	263.6	296.0	266.2
Denver	277.9	318.3	284.7
Salt Lake City	276.4	319.3	290.1
PAD IV avg.	272.6	311.2	280.3
Los Angeles	263.6	322.1	329.5
Phoenix	270.6	308.0	301.0
Portland	276.0	319.3	297.8
San Diego	281.7	340.2	336.2
San Francisco	280.4	338.9	335.4
Seattle	258.7	311.1	314.8
PAD V avg.	271.8	323.3	319.1
Week's avg.	**265.2**	**308.8**	**285.8**
May avg.	**264.1**	**307.6**	**288.5**
Apr. avg.	**234.7**	**278.3**	**270.5**
2007 to date	**222.0**	**265.6**	—
2006 to date	**212.6**	**255.6**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

	6-15-07 ¢/gal		6-15-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	222.50	New York Harbor	201.06
Gulf Coast	220.50	Gulf Coast	198.06
Los Angeles	224.30	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	208.07	ARA	199.13
Singapore	201.43	Singapore	195.60
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	229.50	New York Harbor	131.86
Gulf Coast	227.05	Gulf Coast	134.52
114.77 Los Angeles	235.30	Los Angeles	138.52
		ARA	114.77
		Singapore	134.88

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	6-22-07	6-23-06
Alabama	7	5
Alaska	7	9
Arkansas	47	23
California	33	34
Land	32	31
Offshore	1	3
Colorado	110	84
Florida	1	0
Illinois	0	0
Indiana	3	0
Kansas	14	10
Kentucky	8	6
Louisiana	180	188
N. Land	59	59
S. Inland waters	23	19
S. Land	32	34
Offshore	66	76
Maryland	0	0
Michigan	1	2
Mississippi	13	11
Montana	15	25
Nebraska	1	0
New Mexico	82	100
New York	5	6
North Dakota	35	30
Ohio	13	6
Oklahoma	195	183
Pennsylvania	13	17
South Dakota	4	1
Texas	825	752
Offshore	13	11
Inland waters	0	4
Dist. 1	22	22
Dist. 2	29	64
Dist. 3	59	61
Dist. 4	90	77
Dist. 5	174	134
Dist. 6	120	113
Dist. 7B	34	43
Dist. 7C	56	38
Dist. 8	110	91
Dist. 8A	28	32
Dist. 9	31	37
Dist. 10	59	64
Utah	39	43
West Virginia	35	24
Wyoming	75	107
Others—NV-3; TN-3; VA-3; WA-1	10	3
Total US	**1,771**	**1,669**
Total Canada	**205**	**392**
Grand total	**1,976**	**2,061**
Oil rigs	271	294
Gas rigs	1,495	1,371
Total offshore	81	91
Total cum. avg. YTD	**1,745**	**1,575**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	Rig count	6-15-07 Percent footage*	Rig count	6-16-06 Percent footage*
0-2,500	62	6.4	51	1.9
2,501-5,000	112	52.6	86	39.5
5,001-7,500	239	21.3	233	19.3
7,501-10,000	418	2.8	372	3.7
10,001-12,500	452	1.9	410	2.1
12,501-15,000	273	—	265	—
15,001-17,500	105	0.9	108	—
17,501-20,000	71	—	82	—
20,001-over	38	—	24	—
Total	**1,770**	**7.6**	**1,631**	**6.3**
INLAND	45		42	
LAND	1,654		1,511	
OFFSHORE	71		78	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]6-22-07	[2]6-23-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	20
Alaska	764	785
California	664	686
Colorado	49	61
Florida	7	6
Illinois	30	28
Kansas	94	99
Louisiana	1,353	1,307
Michigan	14	15
Mississippi	48	48
Montana	90	98
New Mexico	163	160
North Dakota	104	112
Oklahoma	162	171
Texas	1,315	1,343
Utah	44	47
Wyoming	142	124
All others	60	74
Total	**5,121**	**5,184**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

$/bbl*	6-22-07
Alaska-North Slope 27°	56.11
South Louisiana Sweet	72.75
California-Kern River 13°	59.60
Lost Hills 30°	67.65
Southwest Wyoming Sweet	65.14
East Texas Sweet	65.25
West Texas Sour 34°	58.90
West Texas Intermediate	65.75
Oklahoma Sweet	65.75
Texas Upper Gulf Coast	62.50
Michigan Sour	58.75
Kansas Common	64.75
North Dakota Sweet	61.25

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	6-15-07
United Kingdom-Brent 38°	69.57
Russia-Urals 32°	66.42
Saudi Light 34°	65.07
Dubai Fateh 32°	65.15
Algeria Saharan 44°	70.93
Nigeria-Bonny Light 37°	71.42
Indonesia-Minas 34°	67.80
Venezuela-Tia Juana Light 31°	63.60
Mexico-Isthmus 33°	63.49
OPEC basket	66.78
Total OPEC[2]	66.63
Total non-OPEC[2]	66.65
Total world[2]	66.18
US imports[3]	63.45

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	6-15-07	6-8-07	Change
	bcf		
Producing region	832	816	16
Consuming region east	1,157	1,097	60
Consuming region west	355	342	13
Total US	**2,344**	**2,255**	**89**
	Mar. 07	**Mar. 06**	**Change, %**
Total US[2]	**1,603**	**1,692**	**–5.3**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration.
Data available in OGJ Online Research Center.

PACE REFINING MARGINS

	Apr. 2007	May 2007	June 2007	June 2006	Change 2007 vs. 2006	Change, % 2007 vs. 2006
	$/bbl					
US Gulf Coast						
West Texas Sour	23.69	28.98	21.95	19.69	2.26	11.5
Composite US Gulf Refinery	23.98	26.18	21.34	20.62	0.72	3.5
Arabian Light	24.84	26.42	21.97	18.70	3.27	17.5
Bonny Light	14.97	18.30	14.04	14.82	–0.78	–5.3
US PADD II						
Chicago (WTI)	25.93	39.21	25.60	19.32	6.28	32.5
US East Coast						
NY Harbor (Arab Med)	20.18	23.61	18.30	15.90	2.40	15.1
East Coast Comp-RFG	23.07	26.23	21.62	19.54	2.08	10.7
US West Coast						
Los Angeles (ANS)	30.05	28.30	21.03	19.72	1.31	6.6
NW Europe						
Rotterdam (Brent)	4.69	7.42	7.68	4.64	3.04	65.4
Mediterranean						
Italy (Urals)	10.27	12.07	9.52	11.29	–1.77	–15.6
Far East						
Singapore (Dubai)	8.89	9.71	8.25	3.65	4.60	126.0

Source: Jacobs Consultancy Inc. NOTE: June 2007 margins reflect prices through 6-21-2007.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Mar. 2007	Feb. 2007	Mar. 2006	Mar. 2007-2006 change	Total YTD 2007	Total YTD 2006	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	2,107	2,555	2,137	–30	7,111	6,454	657
Addition to storage	221	50	131	90	327	295	32
Exports	74	68	69	5	219	184	35
Canada	37	31	37	—	107	102	5
Mexico	32	32	26	6	97	65	32
LNG	5	5	6	–1	15	17	–2
Total demand	**2,402**	**2,673**	**2,337**	**65**	**7,657**	**6,933**	**724**
SUPPLY							
Production (dry gas)	1,598	1,422	1,572	26	4,601	4,532	69
Supplemental gas	6	6	6	—	18	17	1
Storage withdrawal	269	782	331	–62	1,791	1,244	547
Imports	371	357	355	16	1,110	1,031	79
Canada	284	313	315	–31	926	917	9
Mexico	0	0	7	–7	0	3	–3
LNG	87	44	33	54	184	111	73
Total supply	**2,244**	**2,567**	**2,264**	**–20**	**7,520**	**6,824**	**696**

NATURAL GAS IN UNDERGROUND STORAGE

	Mar. 2007	Feb. 2007	Jan. 2007	Mar. 2006	Change
	bcf				
Base gas	4,225	4,214	4,215	4,197	28
Working gas	1,603	1,649	2,379	1,692	–89
Total gas	**5,828**	**5,863**	**6,594**	**5,889**	**–61**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

WORLDWIDE NGL PRODUCTION

	Mar. 2007	Feb. 2007	3 month average Production 2007	3 month average Production 2006	Change vs. previous year Volume	Change vs. previous year %
	1,000 b/d					
Brazil	85	88	86	83	4	4.3
Canada	710	764	730	706	25	3.5
Mexico	416	405	411	435	–25	–5.7
United States	1,767	1,706	1,714	1,683	31	1.9
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	160	158	161	167	–6	–3.3
Western Hemisphere	**3,337**	**3,320**	**3,303**	**3,274**	**29**	**0.9**
Norway	276	311	301	302	–1	–0.3
United Kingdom	159	164	164	164	—	–0.1
Other Western Europe	19	20	19	20	–1	–2.8
Western Europe	**455**	**495**	**484**	**486**	**–2**	**–0.3**
Russia	398	397	397	410	–13	–3.2
Other FSU	160	160	160	160	—	—
Other Eastern Europe	15	17	16	19	–3	–17.2
Eastern Europe	**573**	**574**	**573**	**589**	**–16**	**–2.8**
Algeria	340	340	340	295	45	15.4
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	193	197	196	182	14	7.7
Africa	**658**	**662**	**661**	**602**	**59**	**9.9**
Saudi Arabia	1,439	1,439	1,439	1,439	—	—
United Arab Emirates	400	400	400	400	—	—
Other Middle East	680	680	680	670	10	1.5
Middle East	**2,519**	**2,519**	**2,519**	**2,509**	**10**	**0.4**
Australia	62	79	74	74	—	—
China	180	180	180	180	—	—
India	—	—	13	43	–30	–70.6
Other Asia-Pacific	219	219	219	221	–2	–0.7
Asia-Pacific	**461**	**479**	**486**	**518**	**–32**	**–6.2**
TOTAL WORLD	**8,003**	**8,048**	**8,026**	**7,977**	**49**	**0.6**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Mar. 2007	Feb. 2007	Change	YTD 2007	YTD 2006	Change
	1,000 bbl					
Fuel ethanol						
Production	11,892	10,795	1,097	34,308	26,732	7,576
Stocks	8,529	8,749	–220	8,529	8,708	–179
MTBE						
Production	2,277	1,821	456	5,895	9,312	–20,837
Stocks	1,549	1,792	–243	1,549	2,227	–678

Source: DOE Petroleum Supply Monthly.
Data available in OGJ Online Research Center.

US HEATING DEGREE-DAYS

	May 2007	May 2006	Normal	2007 % change from normal	Total degree days July 1 through May 31 2007	Total degree days July 1 through May 31 2006	Total degree days July 1 through May 31 Normal	% change from normal
New England	245	286	281	–12.8	6,270	6,021	6,545	–4.2
Middle Atlantic	159	199	217	–26.7	5,470	5,239	5,872	–6.8
East North Central	138	241	238	–42.0	6,110	5,785	6,447	–5.2
West North Central	114	200	208	–45.2	6,323	5,891	6,701	–5.6
South Atlantic	49	79	61	–19.7	2,662	2,635	2,846	–6.5
East South Central	34	91	76	–55.3	3,412	3,297	3,597	–5.1
West South Central	12	19	17	–29.4	2,249	1,908	2,286	–1.6
Mountain	175	151	233	–24.9	4,850	4,571	5,127	–5.4
Pacific	118	114	182	–35.2	2,894	2,982	3,152	–8.2
US average*	**107**	**145**	**159**	**–32.7**	**4,226**	**4,044**	**4,485**	**–5.8**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

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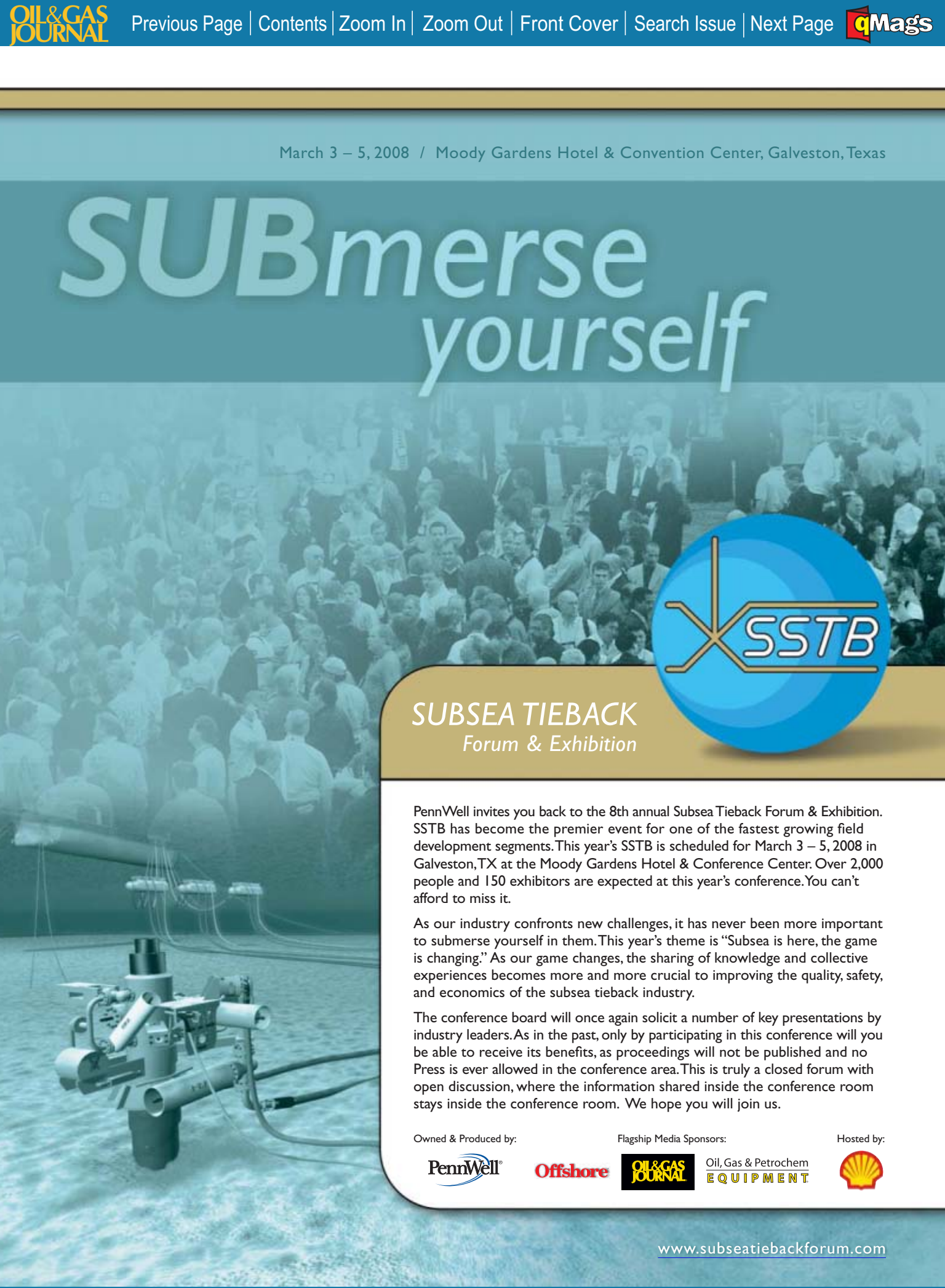

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Senate's energy bill pushes US down wrong road

Throw away the apple from a bowl of rotten fruit, and what do you have? A bowl of rotten fruit.

The US Senate on June 21 rejected punitive taxes on the oil and gas industry but still passed a stinker of an energy bill.

Its discarded package of tax changes would have cost the industry an estimated $26 billion over 10 years (OGJ Online, June 20, 2007). There went the rotten apple.

The Editor's Perspective

by Bob Tippee, Editor

Remaining, however, are major new favors for makers of biofuels and a measure that would make it a crime to charge "unconscionably excessive" prices for oil products in times of strained supply. Other manipulations, less directly related to oil and gas, also fester in the bill: toughened fuel-economy standards for new vehicles, new energy-efficiency standards for appliances and lighting, and spending for the development of fuels politicians like but cost-conscious energy consumers don't.

The bill pushes the US further down a dangerous road toward fuel choice by politicians. Peril already is evident in the leaping food costs that have accompanied congressionally mandated use of corn for fuel. The Senate bill would aggravate the problem.

The political thinking behind these mistakes is equally putrid.

"The time has come for us to give the same kinds of incentives to other industries—alternative energy, renewable fuels, clean-coal technologies, and so forth—that the oil and gas industry has enjoyed for decades and decades," opined Sen. Max Baucus (D-Mont.).

Yes, incentives for the production of oil and gas have come and gone over the years. But when was there anything like the simultaneous market mandates, protectionist tariffs, and whopper tax credits now creating a boom for otherwise uneconomic ethanol and biodiesel?

And where is the one no-cost move Congress can make to give US energy supply the meaningful and economic lift it needs—opening off-limits federal land to oil and gas leasing and development?

Nowhere, of course—not in a political climate misshapen by spite over the price of gasoline. That void, which no one is talking about filling, makes the Senate's bowl of rotten energy produce smell all the worse.

(Online June 22, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Higher prices threaten demand

Demand for crude may fall if prices exceed $80/bbl, said analysts in the Houston office of Raymond James & Associates Inc.

"At almost $70/bbl, oil is currently trading at the same level that it was following the spike caused by Hurricanes Katrina and Rita in 2005," Raymond James analysts reported June 22. Market fundamentals remain strong with dwindling excess production capacity of the Organization of Petroleum Exporting Countries, limited growth in non-OPEC supplies, geopolitical risks, and "the thirst of a relatively strong world economy," they said. "At this point, our main fear for oil is whether prices climb high enough to stir 'demand destruction' concerns. We believe that a price north of $80/bbl is when such fears likely become justified," Raymond James analysts said.

As labor unions in Nigeria rejected government offers to avert a nationwide strike, the July contract for benchmark US light, sweet crudes traded as high as $69.56/bbl before closing at $69.10/bbl June 19, the highest front-month finish on the New York Mercantile Exchange since Sept. 1. That contract expired June 20 at $68.19/bbl June 20 as traders switched their focus to an unexpected jump in US crude inventories to a 9-year high. The new front-month August crude contract dropped 21¢ to $68.65/bbl June 21 on NYMEX with Nigeria's oil exports still not affected by a strike that paralyzed most of that country's economy.

Attacks on oil field facilities and workers had already reduced Nigeria's production in May to its lowest level since early 2003, said the Paris-based International Energy Agency. Shut-in production averaged 800,000 b/d that month. IEA estimated Nigerian production capacity at 2.49 million b/d, excluding 545,000 b/d considered as long-term shut-in.

US inventories

US crude stocks jumped by 6.9 million bbl to 349.3 million bbl in the week ended June 15 against expectations of a 100,000 bbl draw. US gasoline stocks gained 1.8 million bbl to 203.3 million bbl, still well below average for the time of year. Distillate fuel inventories inched up 100,000 bbl to 122.7 million bbl.

US refined product output declined by 150,000 b/d as gasoline production held flat and all other product rates declined modestly. "The industry average utilization rate, surprisingly, fell from 89.2% to 87.6%, suggesting that the industry continues to contend with downtime issues," said Eitan Bernstein of Friedman, Billings, Ramsey & Co. Inc., Arlington, Va. Product imports rose by 135,000 b/d with a 125,000 b/d increase in gasoline imports.

Crude imports into the US Gulf Coast were "the largest number ever recorded" despite lower Mexican production, said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. "Crude oil stocks in the US are as high as they can be, and there has been in the first half of 2007 no evidence of reduced flows to the US despite the OPEC cuts," Jakob said. "US crude oil stocks should come down with coming higher refinery utilization rate, but the draw is needed as we are basically at peaks of recent known tank space capacity."

Paul Horsnell at Barclays Capital Inc., London, said Gulf Coast imports surged because the economics of holding floating storage in the US Gulf of Mexico collapsed. Due to the narrowing of time spreads [the selling of a nearby option and buying of a more deferred option with the same strike price specified in the contract] for benchmark US crudes, he said, "Cash-and-carry arbitrage, (i.e., buy now, sell later, lock in the prices, and store the oil), is becoming far less attractive." That means that crude held in floating storage off the US—"and there may have been as much as 20 million bbl of it," Horsnell said—must empty into either US gulf or Caribbean facilities.

"Indeed, some of the dynamics of the latest weekly US data suggest that the oil is now finding its way into the data. The most suggestive data points are the 1.4 million b/d rise in crude imports into the US gulf (while imports fell by 700,000 b/d in the rest of the US), and the 6.6 million bbl build in Gulf Coast inventories, accounting for virtually all the overall 6.7 million bbl build. Crude oil imports into the US gulf ran at 7.148 million b/d, the highest ever single week's import level. Having the highest-ever imports into the Gulf Coast at the same time as low imports elsewhere in the US, at a time of high refinery outages, does seem to very strongly suggest that some of that floating storage is now making its way into the numbers," said Horsnell.

(Online June 25, 2007; author's e-mail: samf@ogjonline.com)

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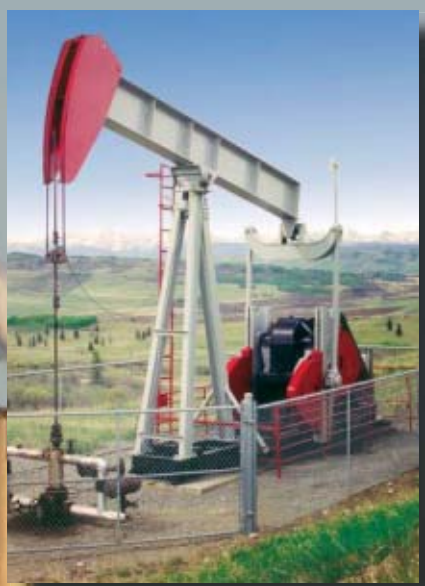

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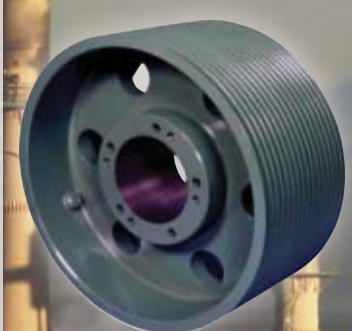

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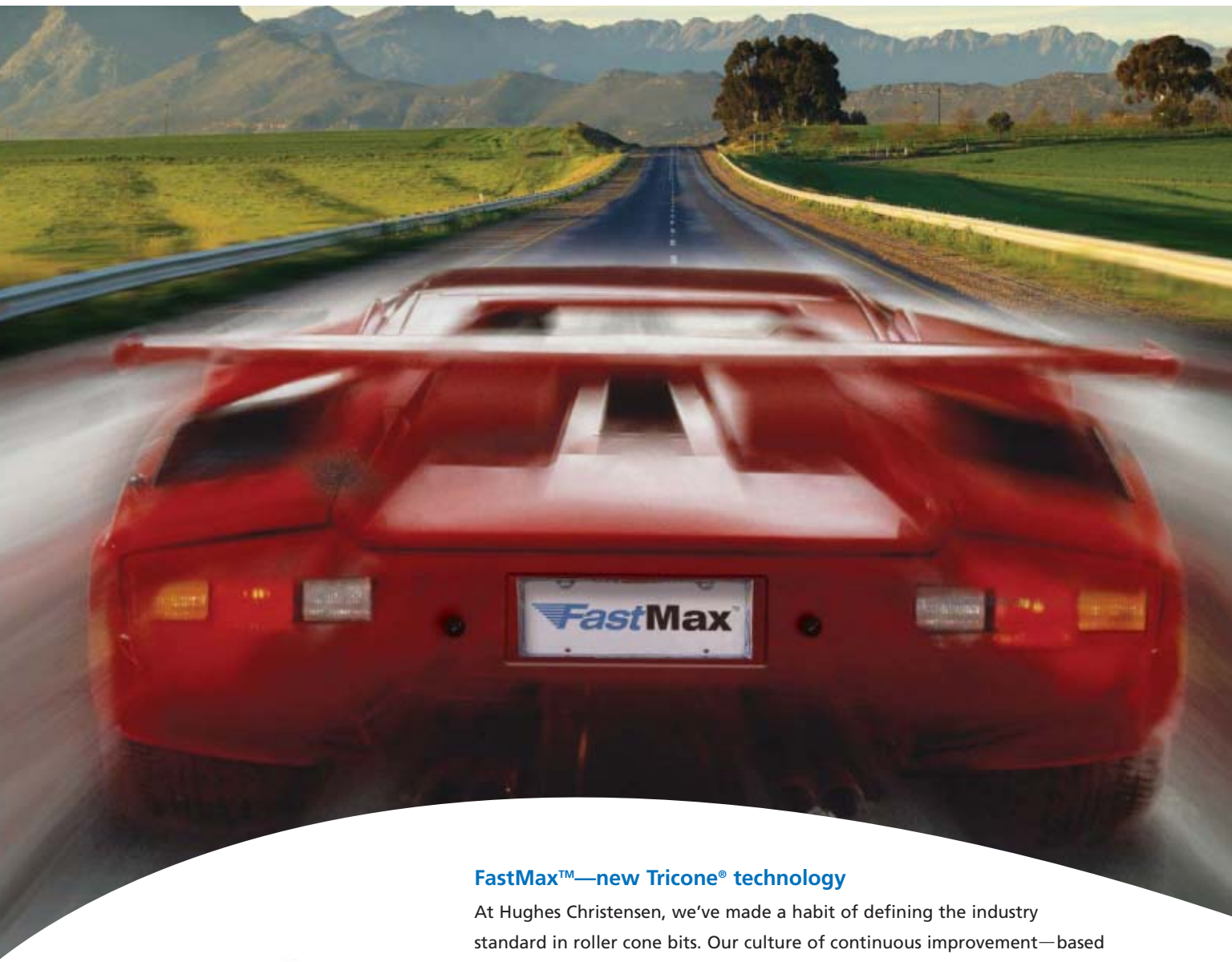

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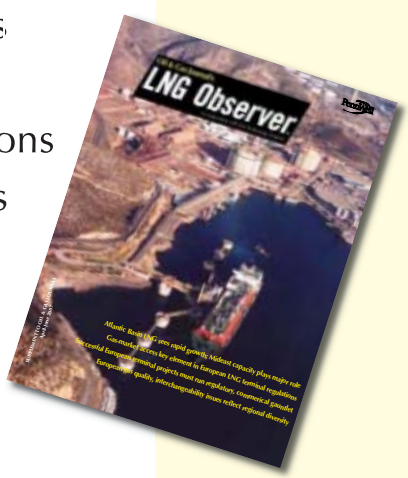

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BP Shipping Ltd.'s 138,000-cu m LNG carrier British Trader, built by Samsung, was commissioned in late 2002 for operating worldwide, rather than a specific trade route. At July 1, 2007, says London-based EA Gibson Shipbrokers, there were 237 LNG carriers in service; a list of LNGCs under construction appears in the Statistics section, beginning on p. 28 of this issue of LNG Observer. Photograph from BP Shipping.

Observations

Issues, Trends, Technologies

Project Updates

Statistics

China's latest FYP points ahead

Warren R. True
Editor

Very little new can be said about China's phenomenal economic growth. Indeed, "phenomenal" itself is so overused it's lost meaning in reference to the country's economy. Even the consistent double-digit annual growth in gross domestic product no longer shocks.

It's a bit of a surprise, then, to see in Oil & Gas Journal's country-by-country data for natural gas reserves and production at yearend 2006 that China was only 15th in proven gas reserves and 11th in natural gas production (OGJ, June 18, 2007, p. 50). In crude oil refining capacity, on the other hand, China's 52 refineries are second only to the US and ahead of Russia (OGJ, Dec. 18, 2006, p. 20).

When, however, someone comes along with historical perspective on just how quickly China's oil and gas segments, particularly its natural gas demand, have developed, it's a useful service. And that's what a report issued in May from FACTS Global Energy has done.

Trends

Analysts at FGE—consisting of FACTS Inc., Honolulu; EWCI Pte. Ltd., Singapore; and EMC, London—poured over numbers for China's 10th Five-Year-Plan, spanning 2001-05 inclusively, and pulled out data to substantiate the country's rapid growth in petroleum and natural gas.

Crude oil production and output of refined products from China's refineries grew an average 11.2%/year for crude oil, 30.1%/year for gasoline, and 56.7%/year for diesel.

Crude production, for example, grew to 3.6 million b/d by yearend 2005 from 3.24 million b/d for 2001. That level doesn't put China in a league with Russia or Saudi Arabia, certainly. But at that growth rate, China is starting to approach US production levels and is already snug with Iran and Mexico.

Perhaps more revealing about economic growth is the growth of crude oil imports over the period: These increased by 81.3%, to 2.5 million b/d in 2005 from 1.4 million b/d in 2001.

Net imports of crude—barrels imported less barrels exported—increased by 98.5%. And import dependency, FGE analysts found, advanced by gulps: 24.4% in 2001, 27.1% in 2002, 33.3% in 2003, 40.8% in 2004, and 39.7% in 2005.

In sum, China's use of crude oil (produced + imported) increased by 41.6%, to nearly 6 million b/d in 2005 from 4.2 million b/d in 2000. Refining accounted for more than 95% of total crude oil consumption.

For natural gas, the story was much the same.

In the 10th FYP, China added proven reserves that more than doubled those from the 9th FYP, to 2.5 trillion cu m (about 88.25 tcf) from 1.2 trillion cu m. Production of natural gas 2000-05 increased by more than 80%, to 50 billion cu m (more than 1.7 tcf). To extend the trend line to 2006, OGJ has stated China's natural gas production for 2006 at 2 tcf (OGJ, Dec. 18, 2006, p. 20).

The FGE report states that China had no gas imports during the 10th FYP. That's true.

In 2006, however, China started up it first LNG terminal, in Guangdong Province. Although Chinese buyers have balked at paying the lofty world prices LNG has been commanding and cargoes into Guangdong have been sporadic since start up, through May 2007 more than 1.5 million tonnes of LNG, or 2 billion cu m (74.5 bcf), have been unloaded there, according to Waterborne Energy, Houston.

The FGE report concludes that Chinese consumption of natural gas in the 10th FYP increased more than 72%, to 46.9 billion cu m in 2005 from 27.2 billion cu m in 2001.

Pacific Basin comeback

For a while, a couple of years ago, industry expectations were that North American LNG demand would surpass the big Asian markets of Japan, Korea, and Taiwan. Those hopes spawned an explosion of nearly 60 terminal proposals. Reality—i.e., market forces and warm winter weather—bit hard, however.

Then it was Europe that was going to drive LNG demand. Winter 2006-07 and plenty of gas cooled forecasters' zeal, however.

Major Pacific Basin markets were thought either mature or, in the case of India and China, unwilling to pay hefty world LNG prices. But Indian LNG buyers have gotten over their reluctance to pay world prices, importing nearly 6.2 million tonnes in 2006 and buying ahead of that pace for 2007.

Trends evident in the 10th FYP strongly suggest China will join India in pushing Pacific Basin demand ahead.

LNG

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Price shocks reveal trends in Atlantic Basin markets

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Europe should play an ever-stronger role in the Atlantic Basin LNG market relative to the US. The demand-supply balance for LNG will fluctuate between balanced and short. Atlantic Basin and Pacific Basin LNG markets will compete for available global LNG supplies.

Particular European countries face some gas surpluses but will resolve them in the next few years. Europe's demand for LNG could become particularly severe if Russia cannot meet its long-term gas supply obligations with the 25 European Union member countries in 2006 plus Switzerland (hereafter, EU25+). To overcome Russian problems, European gas markets would resort to their positions as dominant LNG buyers within the Atlantic Basin, potentially becoming the LNG price setters on a worldwide basis.

The US gas market in contrast to those of Europe likely will use LNG as a marginal gas supply with the main demand for LNG occurring during peak winter heating and summer air conditioning seasons. Such a US LNG demand pattern will in turn lead to large seasonal variations in Atlantic Basin, and probably worldwide, LNG pricing.

These are some of the major conclusions of analyses of US and European natural gas markets and of the likely future LNG supply balance on each side of the Atlantic Basin and between Atlantic Basin and Pacific Basin markets.

Based on a presentation to the 15th Conference and Exhibition on Liquefied Natural Gas—LNG15, Barcelona, Apr. 24-27, 2007

Sources; assumptions

Natural gas supply and demand estimates for these analyses for the US derive from the Energy Information Administration. Forecasts for European gas demand are based on the European Commission DG TREN's "Scenarios on High Oil and Gas Prices" (2006) while a proprietary database as described herein has been used for EU25+ gas supply data. For the Pacific Basin markets, we have relied on a demand forecast by Paris-based Cedigaz.[1] To measure supply we have identified existing and planned additions to liquefaction capacity.

We have included liquefaction capacity at only 90% of its nameplate capacity. If past experience is a guide, however, actual capacity may be as low as 85% of total industry nameplate capacity as operational problems arise with both liquefaction plants and feed-gas supplies. Indonesia, Algeria, Nigeria, Trinidad & Tobago, Egypt, Oman, Malaysia, Qatar, and Australia have all experienced recent operational problems or feed-gas problems.

Some excess liquefaction capacity is necessary to cushion the market against these types of problems, which will likely recur. Although total supply exceeds demand on Fig. 1, the margin is modest and consistent with a balanced market, given the likelihood of technical problems at any point of time. The possibility also exists of delays to the completion of liquefaction trains under construction or being planned beyond the completion dates assumed in our analysis.

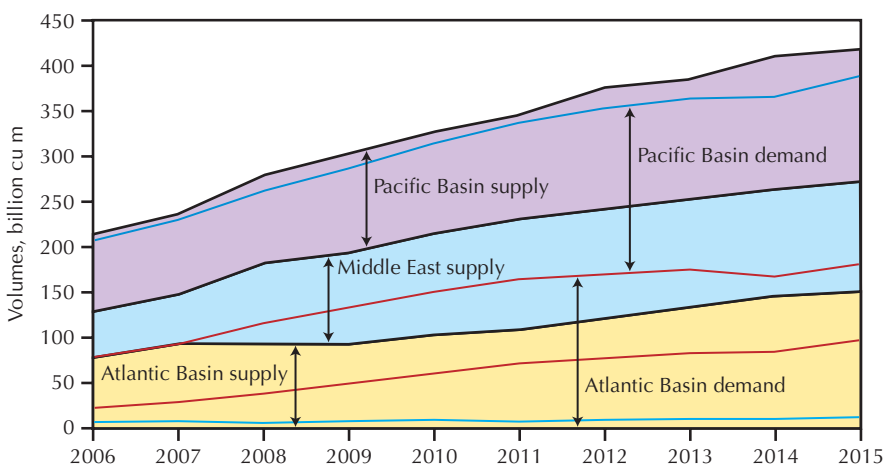
If Fig. 1 had been based on 85% instead of 90% liquefaction-plant nameplate availability, the total worldwide LNG supply in 2007 will be reduced by some 10 million tonnes. This reduction would increase to some 20 million tonnes of LNG product in 2015. These downward LNG supply corrections would be consistent with the current very tight average annual LNG supply situation.

Two winters

Winter 2005-06 displayed unusual characteristics in all major Atlantic Basin gas markets. Average monthly gas prices at Henry Hub (La.) exceeded $13/MMbtu in October 2005 as a result of

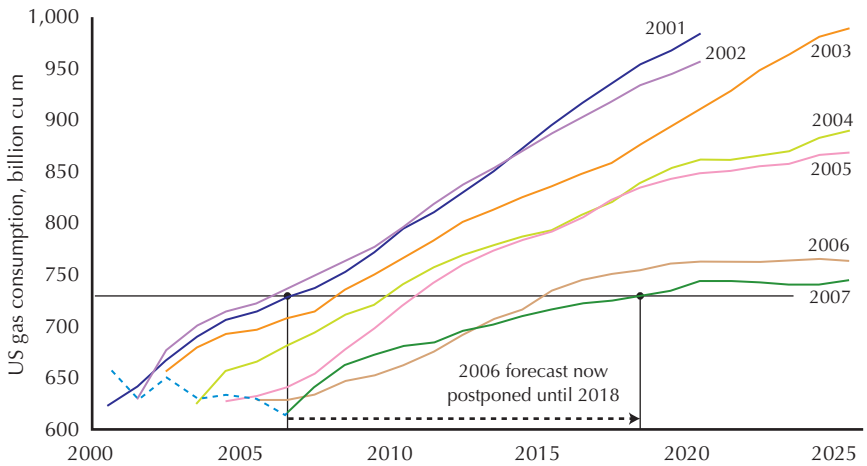
World LNG supply, demand

Fig. 1



EIA gas demand forecasts

Fig. 2



hurricanes Katrina and Rita. Gas prices spiked again during a cold spell in December 2005, but unseasonably mild temperatures followed.

Gas demand fell, prices softened, and large volumes were delivered to storage. Abundant storage stocks depressed US gas prices in 2006 until the air-conditioning season in July and August. LNG imports in 2006 have been estimated at 12.1 million tonnes (16.3 billion cu m) of pipeline-quality gas.[2] Imports were sharply down relative to the 17.8 bcm of pipeline quality gas imported in as LNG 2005.

In contrast to North America, Europe experienced exceptionally cold weather in 2005-06 with record gas demand and high prices both in the liberalized UK gas market as well as in continental Europe. High crude oil prices contributed to high gas prices in the continent due to indexation of long-term gas contracts to oil products.

In January 2006, a gas contract dispute prompted Russia's GazProm to interrupt gas deliveries to Ukraine, a country that moves some 20% of Europe's gas supplies. This interruption was compounded by exceptional cold in Russia and Central Europe. Austria, Germany, France, Italy, the Czech Republic, and Hungary, all witnessed partial curtailments

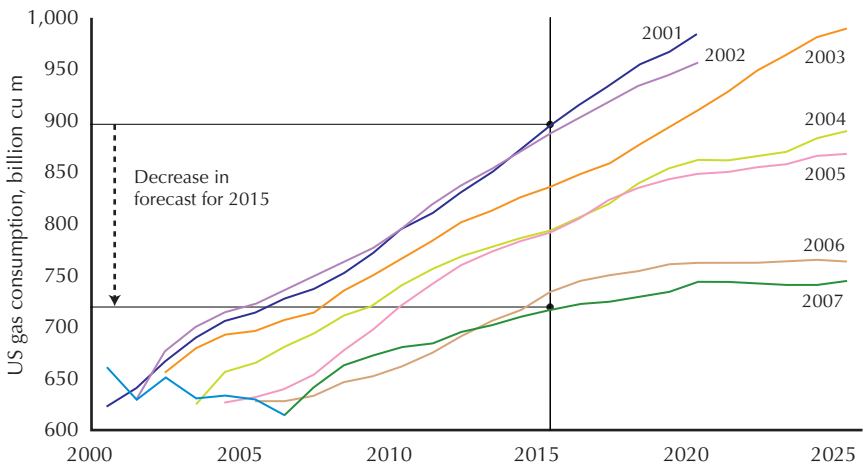
of their Russian gas supplies during most of January and February and part of March 2006.

Drought conditions in Spain, Portugal, and part of France made the energy economies of these three countries depend more than normal on LNG supplies. During winter 2005-06, the average price for LNG delivered ex-ship to Mediterranean LNG receiving terminals ranged $8/MMbtu-$10/MMbtu.[3] Spain in reality set the LNG price for Europe, although higher prices were achieved by the few LNG cargoes delivered to the new LNG terminal at the UK's Isle of Grain that winter.

Winter 2006-07 was relatively similar on both sides of the Atlantic Basin. Both markets saw above seasonally normal temperatures with depressed gas demand, falling gas prices, and more than adequate gas in storage.

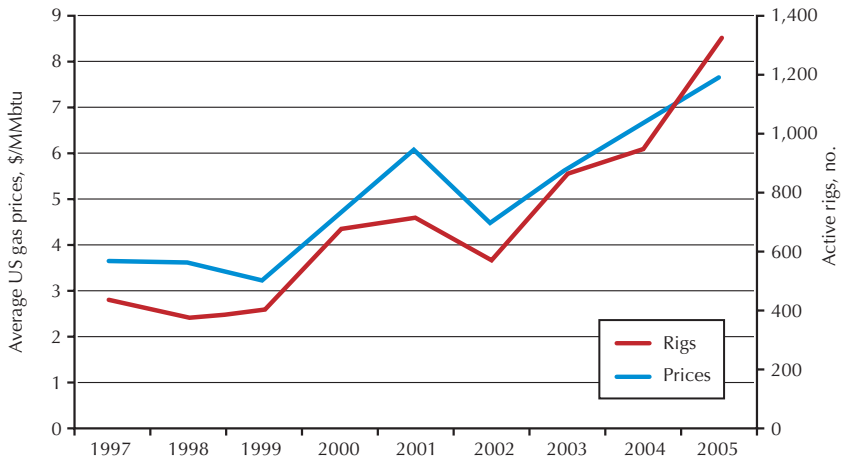
Wholesale gas prices at Chicago and Boston city gates fluctuated $6-8/MMbtu during November and December 2006, reflecting abundant gas in storage. In early January 2007, gas storage in the US Northeast was filled 85-95% of capacity. Chicago and Boston gas price levels mentioned previously are low relative to normal winter prices in these wholesale gas markets, making incremental Canadian gas exports uneconomic. US winter gas demand

Reduction in EIA gas demand forecasts for 2015 Fig. 3



US drilling chases prices

Fig. 4



Source: EIA

season was saved by relatively cold weather in March 2007.

The low prices available for Canadian gas exports resulted in a dramatic reduction in drilling rigs operated in Alberta and BC. Reduction in Canadian gas drilling during 2006 could result in short-term gas supply problems in the US in second-half 2007. The low level of energy imports to the US in 2006 will continue into 2007 with the exception of LNG as outlined below.

Gas demand in Northwest Europe during winter 2006-07 was until mid January 2007 well below seasonal normal levels for two reasons.

1. Winter temperatures were well above normal. Gas prices in the liberalized UK market softened considerably since the previous winter.

2. Gas futures market for winter 2006-07 peaked in April 2006 and had fallen by some 50% by mid January 2007.

This sharp reduction in UK gas prices appeared to have boosted demand particularly from the power-generation market and energy-intensive industries, many of which were closed down during winter 2005-06 by high gas prices. In January 2007 the UK domestic gas market had yet to benefit from reduced gas prices due to pricing policies of retail gas suppliers.

As in the previous winter, drought conditions in Spain, Portugal, and part of France had again prompted high gas consumption in affected areas. Prices of LNG delivered to Spanish terminals were very high, compared with other Atlantic Basin destinations. The value of LNG delivered ex-ship to Spain during the first week of January 2007 was about $10/MMbtu, while this value in the UK was less than $6/MMbtu. LNG delivered to East Coast terminals also had a value of some $6/MMbtu in early January 2007.

Russia is supplying some 25% of European gas demand. During winter, about a third of this supply (8% of European demand) currently transits Belarus. A gas-supply contract dispute between Russia's GazProm and Belarus threatened to disrupt this gas supply but was resolved in the 11th hour. If this dispute had not been resolved, gas deliveries to Poland, Germany, and the Czech Republic would again have been hit hard.

By spring 2007 the very mild European winter had led to gas oversupply in all markets within EU25+. The value of incremental LNG supplies was nearly half of what could be obtained at US East Coast LNG receiving terminals. The US acted as a supply sink for surplus Atlantic Basin LNG cargoes, and US LNG imports have increased during second and third-quarter 2007 in sharp contrast to a year earlier.

The situation in the liberalized UK gas market has been most unusual during late winter and early spring 2007. That market has acted as a sink for higher priced surplus continental European gas quantities. This has been the case, although gas prices at the National Balancing Point (NBP; the main gas trading hub in Europe, a virtual point within the UK gas transmission system) have been less than half of gas prices in continental Europe that have price indexation based on oil product prices.

What lessons could Atlantic Basin gas market operators learn from winters 2005-06 and 2006-07?

In the US, gas supply appeared better than anticipated only a few years ago. LNG had become a marginal gas supply source, to a large extent drawn upon during weather-induced high electricity and gas demand.

European gas markets experienced tight gas supply conditions with some fuel switching from natural gas during winter 2005-06. Energy markets, however, were generally supplied with gas. Although imperfect, the liberalized UK gas market was functioning during winter 2005-06. The importance of providing a much higher level of storage capacity in the UK and Irish gas markets could not be ignored.

Winter 2005-06 raised more questions about continental European gas markets. High and rising gas prices depressed gas demand in Europe except for the Mediterranean countries. Russia's domestic gas demand and its behavior towards its gas transit countries gave rise to serious concerns about its reliability as Europe's main gas supplier.

US scene

High gas prices are having considerably different effects on demand for LNG in North America and Europe. The differences lie in a combination of demand and supply factors.

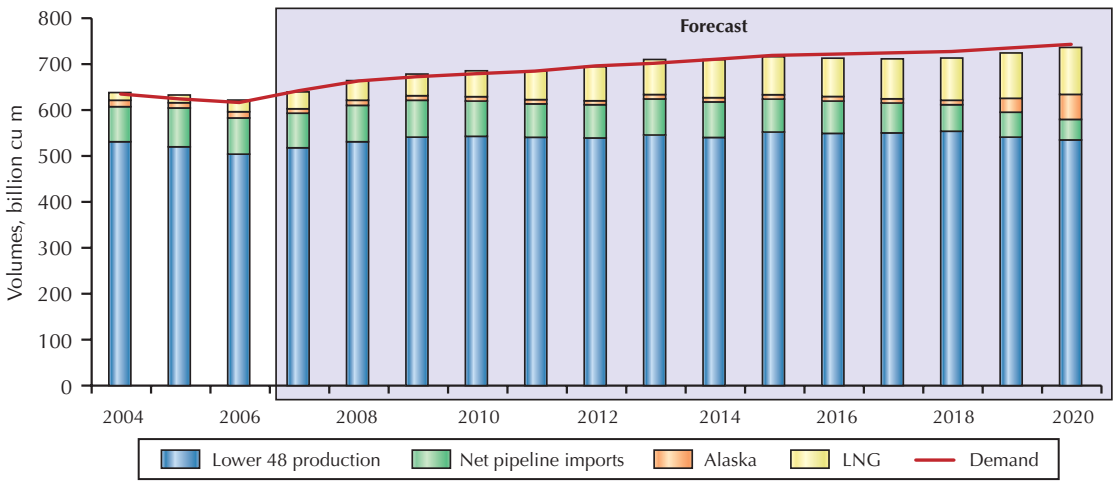
In the US, high prices have led to a significant revision of demand fore-

casts, with serious implications for future LNG imports. The effects in Europe are far more attenuated.

High US prices have prompted higher investment in domestic gas resources. High prices also make coal more attractive to fuel thermal power stations.

These two factors distinguish North American gas markets significantly from Europe: The European gas market cannot respond to high gas prices by accelerating development of indigenous resources. The gas markets of EU25+ can only increase their gas supplies through increased gas imports. Furthermore, Europeans pay roughly twice as much for coal as in the US.

US natural gas supply, demand: projected Fig. 5



Source: Annual Energy Outlook 2007, trade press, Brattle Group Ltd., and Morten Frisch Consulting

Gas demand

The US Energy Information Administration's base case for future US gas demand shows gas demand increasing at 1.7%/year through 2015, to 717 bcm from 615 bcm.[4]

Two years ago, we discussed the successive postponement of gas demand forecasts by the EIA.[5] We noted that US gas demand had stagnated since the onset of high gas prices. Predicting such large increases in demand was unreasonable. Fig. 2 is based on that earlier presentation, showing successive forecasts for 2001-05 and adding the last 2 years' forecasts.

The new 2007 base case confirms those previous concerns, contrasting sharply with the 2000 EIA forecast. As suspected, demand has continued to stagnate.

In early 2001, the forecast was for growth of 105 bcm by 2006. None of that growth has materialized. Actual consumption in 2006 was even less than in 2000.[6] Growth has been zero. The most recent forecast shows that the previous target for 2006 has now been pushed out to 2018.

Forecasts for 2015 have been slashed by even more (Fig. 3). The 2001 forecasts anticipated 895 bcm by 2015, while the new forecast is for only 717 cm. The drop of 178 bcm approximates the current total consumption of the UK and Italy combined, which are two of the largest national markets in Europe.

The US power sector is responsible for much of the change in forecast demand. In 2001, increased demand from the power sector was forecast to drive roughly three quarters of total growth by 2015. The 2007 forecast now shows that there will be no net growth in gas demand from the power sector in the long run. In 2030, the US power sector will consume 209 bcm of gas, virtually unchanged from the 208 bcm consumed last year.

It is difficult to foresee any long-term increase in consumption of natural gas by the power sector, when the average price of coal is so low. Although there is an international market price for coal, it applies only to a few geographic areas in the US that must import coal from overseas due to the lack of available local resources. Many US power companies are in areas with abundant coal reserves, where local market prices are significantly below international levels.

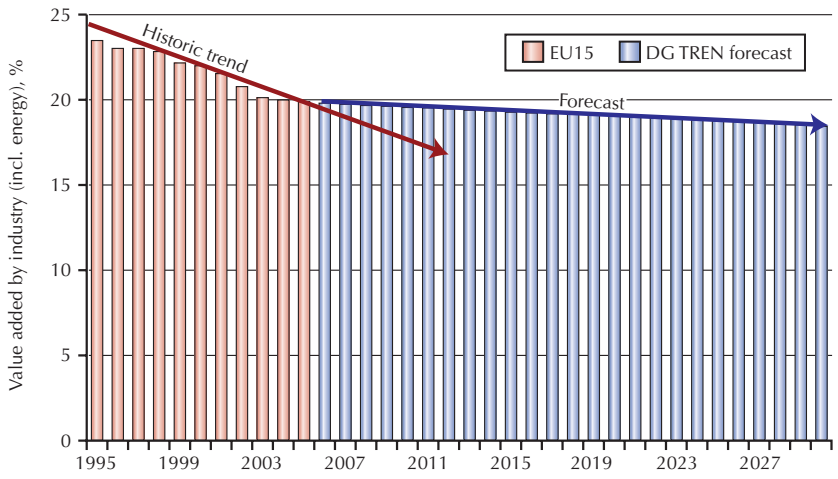
Supply

US natural gas reserves have declined consistently for several years. Drilling activity, however, has demonstrated significant sensitivity to gas prices in both the US and Canada, the latter being a substantial exporter of gas to the US. High gas prices have prompted significant increases in the number of active rigs in the US, to 1,351 in 2007 from 720 in 2000. There is an extremely tight correlation between prices and drilling activity in the US.[7]

Investment in indigenous resources and gas-on-coal competition will together constrain the scope for LNG imports to the US. Imports should still grow relative to current levels, but more slowly than previously thought. Fig. 5 shows a projected supply and demand balance for the US, with LNG imports filling the gap between demand and supplies available to serve domestic sources.

We calculate the available domestic sources to serve the US by including domestic production, Canadian gas pipeline imports, and by deducting anticipated US exports to Mexico. The two large pipeline projects from Canada and Alaska first appear (in orange) in 2011

European industrial sector: historical, projected **Fig. 6**



as part of Alaskan supply with anticipated start up of the McKenzie Valley pipeline and then expanding significantly 2019-20 when the planned gas pipeline from Alaska to the Lower 48 reaches capacity.

European market

Demand

This analysis uses gas demand forecasts prepared by the European Commission's DG TREN, which reflects a comprehensive European effort with consistent projections for each of the EU25+.[8,9] This analysis indicates European demand will be less than forecast.

Strong grounds exist for reducing the forecast by 10 bcm by 2015, which approximates 10% of the forecast growth. The principal conclusion, however, is that high prices in Europe will not lead to a stagnation of gas demand anywhere near the scale that has occurred in the US.

Recent trends suggest a drop in the percentage of total GDP consumed by Europe's industrial sector. The services sector has increased in importance. This trend has a moderating effect on natural gas demand because the service sector uses natural gas less intensively than industry.

The current era of high energy prices should only accelerate Europe's shift from the industrial sector to the service sector. The European Commission, however, forecasts assume an unexplained sharp stagnation of this trend. Fig. 6 shows the historical decline of the EU service sector and the forecast assumed by the commission when developing gas-demand projections.

The commission produces its forecasts once every few years, the latest in 2006. The realism of the forecast can be checked in part by comparing with actual data. The European Central Bank publishes data concerning the size of the industrial sector. In 2005 the industrial sector represented 18.2% of gross domestic product. This percentage is already below the level that the commission had forecast for 2030.

A more reasonable scenario would entail two adjustments to the commission's forecast: departing from the actual data witnessed for 2006, and projecting a continuation of the historical shift from the industrial to the services sector.

Together these adjustments suggest the commission has overstated the consumption of gas by the industrial sector, and slightly underestimated the consumption of gas by the services sector. The net effect, however, is an overstatement of the total demand forecast. Our proposed adjustments would reduce demand by about 7 bcm in 2015.

In the commission's forecasts for gas consumption by the power sector, the main weakness is the assumed retirement of nuclear power stations in Sweden and Germany. This is forecast to prompt construction of more gas-fired power stations as a substitute.

High energy prices exert strong commercial pressures to extend the lives of the nuclear power stations. We assume a continuation of these power stations through 2015. This amendment reduces forecast gas demand by another 3 bcm in 2015.

These proposed adjustments combine to reduce the forecast for Europe by 10 bcm. The total extent of the revision could be higher, but no grounds appear that question a principal aspect of the forecast: increased demand for natural gas by the European power sector.

Based on the Brattle Group's work concerning the economics of nuclear, coal, and gas-fired power stations referred to earlier,[10] nuclear power is now economic in the era of high gas prices. Europe may therefore witness a shift to nuclear power.

The first step would be to extend the lives of existing nuclear power stations, a step now included in our demand forecasts. The next step will be the eventual construction of new nuclear power stations. The political debate on nuclear power, however, has not yet settled.

The timing of new nuclear power stations will depend on the resolution of regulatory uncertainty and on the naturally long lead times for constructing new nuclear power stations. It is difficult to believe that the European market will complete substantial new nuclear capacity before 2015.

We have also considered whether high gas prices might lead to a resurgence of coal-fired power stations in Europe. While coal is more economic than gas in the US, coal has no clear advantage in Europe. Most of Europe pays more than $60/ton for coal, a price that

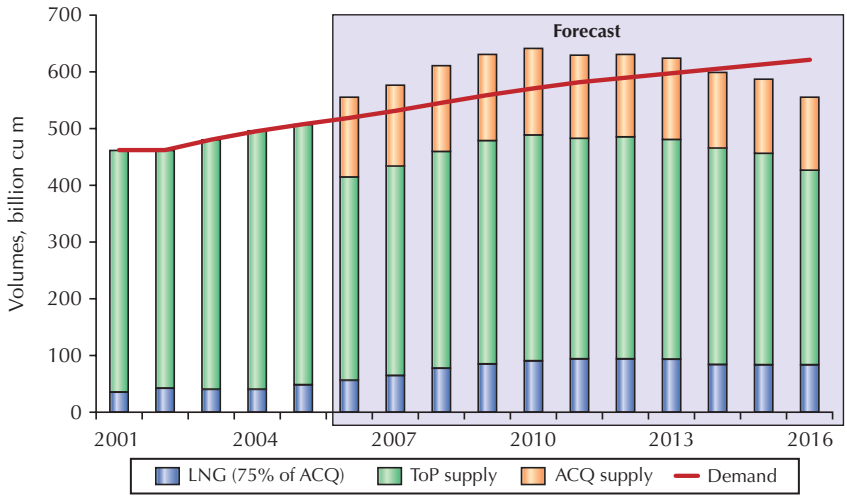
combines with the prospective cost of carbon permits to give the power sector a relatively high tolerance for natural gas prices.

The era of high gas prices has renewed interest in coal, and coal could become clearly more attractive depending on technological breakthroughs in carbon sequestration. Barring a technological breakthrough, however, no major shift to coal in Europe before 2015 is imminent.

Fig. 7 shows our forecast of demand and supply being based on the annual percentage demand growth developed by the commission's DG TREN, which we have applied to historical gas consumption data[11] with the adjustments as previously described. The forecast entails a growth of 96 bcm in natural gas consumption by 2015.

EU25+ supply-demand balance

Fig. 7



Supply

Estimated supplies in Fig. 7 come from our proprietary database that looks at existing import contracts, infrastructure developments, and data on likely domestic European production as well as the major producing countries from which Europe imports pipeline gas. Domestic production volumes (defined domestic as EU25 plus Switzerland), again reflect projections in the European Commission DG TREN[8] and from the ministries or state oil and gas companies of particular gas-producing member states.

To estimate gas imports we considered existing contracts for Algerian, Libyan, Nigerian, Russian, Trinidadian, and Ukrainian supplies. For Norwegian imports we considered the latest gas-production projection issued by the Norwegian Petroleum Directorate,[12] modified to match available gas transportation infrastructure. LNG supplies from Egypt, Oman, Qatar, and Yemen were derived from a mixture of contracted quantities and LNG infrastructure investments tied to the particular producer in European countries.

Observations in the European gas market led to modification of LNG supplies to reflect actual deliveries as outlined presently. We project gas trade among EU25+ countries, based on information about individual gas sale and purchase agreements as well as swap arrangements.

Both annual contract quantities (ACQs) and delivery flexibility expressed as take-or-pay (ToP) levels were considered. For LNG supplies, we have set the ACQ for LNG receiving terminals at 90% of the design capacity. Similarly we have set the ACQ under long-term LNG supply agreements at 90% of the ACQ. As the norm we have applied 75% of this "adjusted ACQ" as the regular annual delivery under each contract. When the buyer and the seller of the LNG are the same, we include only 50% of the adjusted ACQ to reflect the merchant nature of such projects.

The difference between ACQ and ToP levels indicates the supply flexibility for each country as well as EU25+ as a whole. Consistent with current practice in the European gas market, we assign long-distance gas pipeline supplies a high ToP level, 85% ACQ to reflect the base-load nature of these contracts.

For long-term LNG contracts as well as LNG merchant or trading arrangements, we set ToP levels uniformly at 50% of the adjusted ACQ, reflecting the ability of suppliers as well as buyers to divert LNG cargoes to markets outside Europe.

Fig. 7 shows the gas supply and demand balance for EU25+ expressed as ACQ as well as ToP. Our analysis suggests that EU25+ is likely to have a balanced position between projected demand and supply until 2013, since the demand curve intersects supply between the ACQ and the ToP levels.

Some 25% of the gas demand within EU 25+ is supplied under Russian gas export contracts, most of which are of long-term. The reliability of these contracts has come into question after continental European countries' experiences with their Russian gas supplies during winter 2005-06.

A closer analysis of Russian gas production and transportation facilities and arrangements poses serious concerns for the short and medium-term security of supply of Russian energy including natural gas. These concerns are independent of the Ukrainian gas supply episode in January 2006 and of the Belarusian oil transits situation, which reflected a gas supply dispute between Russia and Belarus, during January 2007.

Looking further ahead, Russia's gas consumption will continue to grow rapidly unless its domestic gas prices adjust to reflect international levels. Such price adjustments are needed for

two reasons:

1. To stem domestic demand.
2. To provide GazProm with necessary funds to step-up dramatically its investments in gas exploration and production in Russia and maintain and upgrade the vast gas transmission system.

Although the country has the largest gas reserves in the world and possesses a huge gas production potential, it currently extracts 50% of its gas production from fields already in advanced stages of decline.[13]

Russia had hoped to import large quantities of gas at low prices from central Asian republics, Turkmenistan and Kazakhstan in particular, at least in part to compensate for Russia's difficulties shoring up declining gas production. Turkmenistan, however, possesses the largest gas reserves among the central Asian republics and has started gas-sales negotiations with China.

Russia could face a gas supply gap of up to 126 bcm/year by 2010 even under the most optimistic import scenario for gas deliveries from central Asia with the supply of 105 bcm/year.[14] Increasing internal gas prices, however, to reflect international levels better could curtail Russian domestic gas demand significantly, reducing the predicted supply gap to manageable levels.

Close observers of the Russian gas industry agree that GazProm must allow independent oil and gas producers in Russia access to its pipeline system and must pay a reasonable price for such gas supplies.[13 14] This is likely the only way to remove the predicted gas supply gap in 2010. Currently some 60-80 bcm of gas is flared in Russia due largely to the lack of access to GazProm's pipeline system. GazProm must provide clear price signals to independent oil and gas producers without delay, however, to motivate necessary gas developments and infrastructure investments.

Except for Spain and Portugal, LNG still represents a small fraction of Europe's total gas supplies. LNG should in the future, however, become of greater interest to the Europeans because of the diversification it offers. With diversification comes safety. The EU's recent inquiry into competition in the natural gas industry points to LNG as a hope for both enhanced security and increased competition.[15]

LNG in Atlantic Basin

Multiple price drivers are developing in Atlantic Basin gas markets as the growth in LNG promotes interconnection. The strongest drivers over the past 2 years have been the unusual circumstances in Spain: Drought reduced generation of hydroelectric power, requiring significantly higher outputs from gas-fired power stations and raising natural gas demand. Spain's influence has also stemmed from its position of prominence as the largest importer of natural gas in the Atlantic Basin. Spain also had a severe winter in 2005-06.

In the future, weather conditions and the Russian situation will determine whether Europe or North America will drive winter LNG prices. Europe will be more important for LNG exporters in terms of its annual demand. The air-conditioning peak in the US summer markets, however, will exert a strong influence. The capacity of US regasification terminals will likely exceed the demand for LNG.

We have compared EIA's forecast of LNG imports to the maximum realistic capacities for the existing regasification terminals and those likely to be built. We again set the ACQ as 10% of nameplate capacity for the regas terminals and the sustainable annual capacity as 67% of the nameplate capacity corresponding to 75% of the ACQ.

Our analysis reveals a prospective utilization of US re-gas terminals in the range 25-30% of total nameplate capacity, corresponding to 38-44% of the 75% ACQ sustainable capacity, through to 2015. The resulting excess capacity and prospective low utilization of regas terminals is consistent with our view of the US exerting a strong seasonal influence on the Atlantic Basin.

We have performed the same LNG analysis for Europe, comparing the sustainable capacity of European regas terminals with our own LNG demand forecasts based on the proprietary database described earlier. We have verified this forecast against Cedigaz' forecast of demand for LNG.[16]

In Europe, terminal utilization will be closer to baseload operations, particularly if Russia should have difficulty meeting contractual obligations. Our analysis suggests utilization rates ranging 78-93% of the total sustainable annual regas capacity over the forecast period.

The Pacific Basin is another strong and growing influence on the Atlantic Basin.[17] To date, available Atlantic Basin liquefaction capacity has been roughly equal to baseload demand for Atlantic Basin regas capacity. It was technically feasible for Atlantic Basin consumers to rely exclusively on Atlantic Basin producers, although there has been active trade with LNG producers in the Arabian Gulf and LNG cargoes from the Pacific Basin have been delivered to Atlantic Basin markets.

Atlantic Basin demand growth will soon increase its reliance on Arabian Gulf supplies. As Fig. 1 shows, demand in both Atlantic and Pacific basins will exceed liquefaction capacity in either area. Each basin will therefore seek Middle East supplies to balance respective markets. Although it has been assumed that no Iranian LNG project will come on stream before 2015 and that Qatari LNG capacity in this period will not exceed the 77.2 million tonnes/year currently operational or under construction, LNG capacity could in fact nearly double by 2015 to accommodate forecast demand.

Acknowledgment

Marie-Francoise Chabrelie, secretary general of Cedigaz, Paris, has provided invaluable help in our development of future LNG supply and demand scenarios. **LNG**

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China making bid to lead LNG carrier building

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China aims to become the world's leading shipbuilder by 2015.

The country's shipbuilding industry's current competitive advantages favor tankers, bulk carriers, and other relatively "simple" ship types. The National Development and Reform Commission (NDRC) and other key agencies in Beijing are encouraging Chinese shipbuilders to build more sophisticated ships, among them LNG carriers.[1]

China's primary LNG carrier building yard, Hudong-Zhonghua, began researching LNG carrier construction in 1997 and began building in 2004.[2] The 147,000-cu m Dapeng Sun and Dapeng Moon have been launched and will enter service in late 2007 and 2008, respectively.[3]

The Marine Research and Design Institute of China designed both vessels, which were built in China State Shipbuilding Corp.'s Hudong-Zhonghua Shipyard with technical assistance from French shipbuilder Chantiers de l'Atlantique (now Aker France).[4]

Although high global LNG prices are temporarily curtailing Chinese LNG demand, Chinese shipbuilders are beginning to build LNG carriers. Chinese yards currently have three more large LNGCs on order, and six small 10,000-cu m LNG/ethylene carriers on order.

Table 1 shows China's current LNG carrier orderbook.

Hudong Zhonghua, Jiangnan Changxing, Nantong COSCO KHI, and Dalian New Shipyard all have LNG carrier building ambitions. Hudong Zhonghua already dominates the Chinese LNGC orderbook. Chinese domestic LNG carriage needs will likely be too small to support all of these yards.

In this environment, other yards interested in building LNGCs will have little choice but to look for international buyers right away. Lloyd's Sea Web shows that the Nantong COSCO KHI yard (a joint venture with Japan's Kawasaki Heavy Industries) may soon build a 174,000-cu m LNG carrier for Algerian state energy producer Sonatrach.

China's LNG carrier ambitions are currently driven by politics rather than the cost advantages that Chinese yards enjoy when building tankers and bulk carriers. As the Chinese shipbuilding industry continues to modernize, however, its LNGC builders could become commercially competitive by 2015. To break into the market, they would need to cut ship prices drastically or find other ways to differentiate themselves from Korean yards.

At present, Chinese yards are building large LNGCs for Chinese buyers. Yet Norwegian ship owner I.M. Skaugen has ordered six small LNG/ethylene carriers. The fact that an established international firm is buying Chinese

China's current LNG carrier orderbook*

Table 1

Name of ship	Shipbuilder	Gas capacity, cu m	Delivery year	Status	Operator	Group owner
Da Peng Moon	Hudong	147,200	2008	Launched	Guangdong Dapeng LNG Co Ltd.	China govt.
Da Peng Sun	Hudong	147,200	2007	Launched	Guangdong Dapeng LNG Co Ltd.	China govt.
Hudong H1320A	Hudong	147,200	2008	On order/not commenced	Guangdong Dapeng LNG Co Ltd.	China govt.
Hudong H1379A	Hudong	145,200	2008	On order/not commenced	COSCO	COSCO
Nantong COSCO KHI	Nantong Cosco Khl	155,000	2009	Projected	Sonatrach	Sonatech Petroleum
Taizhou Wuzhou	Taizhou Wuzhou Shipbuilding	10,000	2010	On order/not commenced	Norgas Carriers	Skaugen
Taizhou Wuzhou	Taizhou Wuzhou Shipbuilding	10,000	2010	Projected	Norgas Carriers	Skaugen
Taizhou Wuzhou	Taizhou Wuzhou Shipbuilding	10,000	2007	On order/not commenced	Norgas Carriers	Skaugen
Taizhou Wuzhou	Taizhou Wuzhou Shipbuilding	10,000	2008	On order/not commenced	Norgas Carriers	Skaugen
Taizhou Wuzhou	Taizhou Wuzhou Shipbuilding	10,000	2009	On order/not commenced	Norgas Carriers	Skaugen
Taizhou Wuzhou	Taizhou Wuzhou Shipbuilding	10,000	2009	On order/not commenced	Norgas Carriers	Skaugen
Taizhou Wuzhou	Taizhou Wuzhou Shipbuilding	10,000	2009	On order/not commenced	Norgas Carriers	Skaugen

*As of July 1, 2007
Source: Lloyd's Sea Web

vessels reflects the Chinese shipbuilding industry's rapidly improving quality. In interviews, ship operators said that within 3-4 years, they would consider purchasing Chinese made LNG carriers.[5]

Why build LNG carriers?

At present, China's LNG carrier ambitions appear to be driven primarily by politics.

Beijing emphasizes using Chinese built ships to haul Chinese LNG imports. Chinese officials also obsess over cracking the market for such "high value-added" ship types as LNGCs. These vessels may in fact be no more profitable to build than VLCCs, bulk carriers, and other simpler ships.[6]

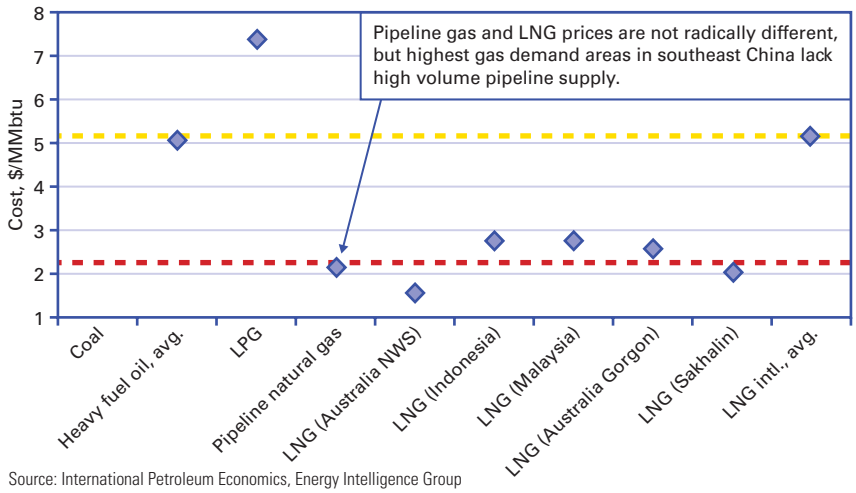
China's shipbuilding industry is progressing rapidly. For the next few years, however, it would make more economic sense for Chinese shipbuilders to focus on bulkers, tankers, and container ships that dominate their orderbooks. China is already a global oil tanker-building powerhouse, capturing nearly a third of new global VLCC orders in 2006.[7] Yet oil tankers are relatively simple to construct, while LNG carriers are one of the most complex civilian ship types.

Shanghai Waigaoqiao and Dalian New Heavy Ship Industry Co. are now globally ranked as Nos. 8 and 9, respectively, most-competitive yards.[8] Yet their economic competitiveness is most pronounced in these simple to mid-complexity ship types. With respect to specialty vessels, Chinese builders may find readier markets in the near term for chemical and LPG tankers, rather than LNG carriers.

Table 2 shows key differences between building oil and LNG tankers.

COAL VS. COMPETING FUELS IN CHINA

Fig. 1



Source: International Petroleum Economics, Energy Intelligence Group

Chinese yards are working hard to gain LNG shipbuilding capacity relative to foreign competitors. They are actively seeking joint ventures in order to acquire foreign capital and technology. These JVs will operate under the principle that China "should cooperate with foreign companies, but also must control and preserve a large national stake."[9]

At present, China's main LNGC building yard, Jiangnan Hudong, is a partner with French builder Chantiers de l'Atlantique (now owned by Aker Kvaerner of Norway).[10] Chantiers may see the Chinese market as a last chance to profit from LNG tanker construction since South Korean and Japanese LNG builders have pushed Chantiers and other European shipbuilders almost completely out of that business.

China can rapidly assimilate technologies gained through JVs. When Australian firm INCAT first provided wave-piercing catamaran vessels to Hong Kong firm AFAI in 1994, the Australians believed that the Chinese would be unable to reverse-engineer the highly complex catamaran. Yet in April 2004, China launched the Type 2208 Houbei missile boat, which drew heavily on the Australian wave- piercing catamaran design.

On the economic front, Chinese analysts believe that building LNG carriers and other "complex" ships will promote the growth of China's shipbuilding industry and note that constructing both crude oil and LNG tankers involves iron and steel production, metallurgy, electronics, shipbuilding, and harbor construction.[11] LNG carrier construction draws on many of the same industries as oil tanker building, where building one 300,000-dwt VLCC can create up to 6 million man-hr of employment.[12]

LNG carriers are more complex than VLCCs and would likely require substantially more man-hr/dwt to build.

KEY DIFFERENCES BETWEEN OIL & LNG TANKERS*

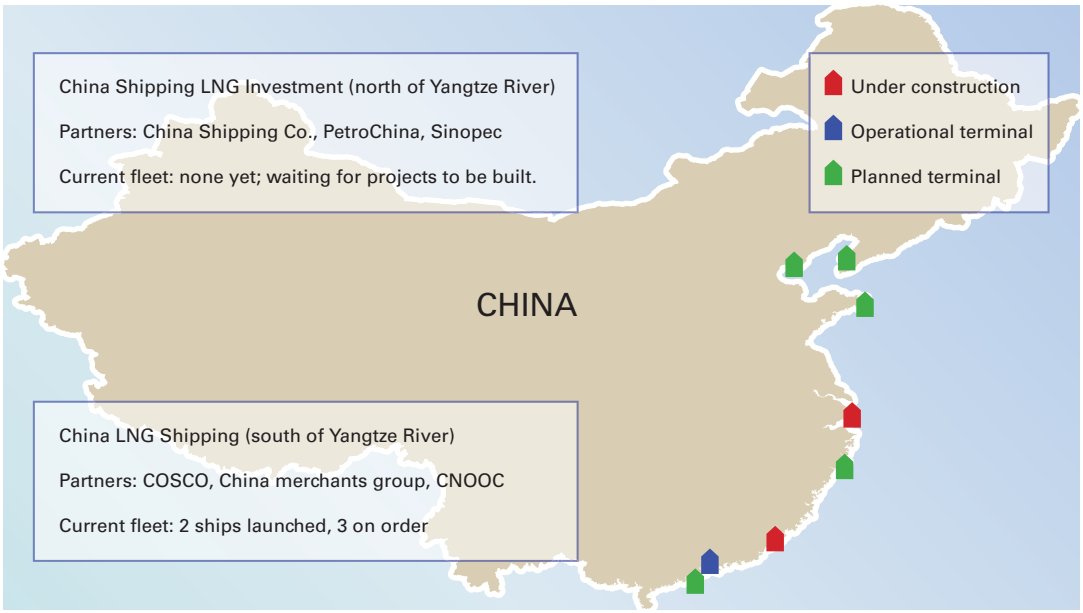
Table 2

Oil tankers	LNG carriers
Oil tankers relatively simple to build.	LNG carriers more complex.
Less need for tech transfer. Chinese oil market initially served largely by foreign shippers. Now a strong push to increase share of "nationally hauled" oil imports.	Strong desire for JVs and tech transfer. Chinese market initially served by Chinese shippers.
Oil tanker sector already experiences significant demands for replacement tonnage.	LNG ships are long lived and demand comes in "spurts." There is not yet a serious call for replacement tonnage.
Oil tankers are often built speculatively.	LNG carriers are typically built for specific projects.

*In China, both types of tankers are built under the political banner of "improving energy supply security" but in reality are being constructed largely for commercial gain.

China LNG shipping companies

Fig. 2



Source: Platt's International Gas Report

In addition, building an LNG supply chain also requires building specialized wharves and regasification terminals. China is studying other portions of the LNG value chain such as regasification terminal construction.

The economic benefits of developing an LNG industry could be substantial since, according to the NDRC, China must create 25 million new jobs each year to meet demands created by university graduation, state-owned enterprise restructuring, and rural migration to cities.

This is a clear barometer of China's interest in developing its domestic LNG industry. It could also have international implications in the longer term if Chinese engineering firms begin working on overseas LNG infrastructure, since a shortage of construction and engineering firms is one of the current key constraints on international LNG development.

China's LNG fleet plans and the ongoing oil tanker fleet buildup are very similar. In essence, shipyards are reaping great rewards from the central government's need to create jobs and its sense of energy insecurity. Chinese language articles often cite the "need to ensure stable shipments at fair prices" as a key reason for building a Chinese-run LNG carrier fleet.

From the commercial perspective, however, it remains unclear why international LNG shippers would not be up to the task. Such security arguments also overlook the fact that China LNG Shipping and other firms could simply order their vessels from South Korean yards.

Chinese official policy emphasizes fostering the growth of a domestic LNG fleet by using only ships built in Chinese yards to deliver LNG to Chinese terminals.[13] Thus, China's own LNG import growth will help determine how many LNG carriers Chinese yards can build for the domestic market before they must begin competing with well-established Japanese and South Korean yards for international sales.

LNG demand

In 2005, Chinese analysts estimated that in 2015, China would need up to 35 LNGCs to meet projected LNG import demands of 33 million tonnes/year.[14] The current demand picture appears less optimistic, however. Thus, Sinopec and other companies are delaying projects until the price situation improves. China is rich in coal, making LNG uncompetitive for baseload power generation at prices above $3.50/MMbtu. Yet international LNG prices currently stand near $9-11/MMbtu. Japanese and Korean consumers can afford LNG at these prices, but Chinese cannot.

Fig. 1 compares Chinese coal prices to those of potential competing fuels and shows that average international LNG prices exceed Chinese coal prices by a factor of four and could remain high for several years since new projects can take 5 or more years to come online. A recent spate of world class domestic gas discoveries equal to more than 5 years of imports at China's projected 2010 demand level will erode China's prospective LNG demand.[15] China may also see domestic supply gains from its coalbed methane reserves. Chinese residential gas prices are also controlled, making LNG uncompetitive for residential gas supply at current price levels.

High world LNG prices and increased domestic gas supplies are therefore retarding Chinese LNG demand growth. This will likely reduce the number of ships needed to serve Chinese terminals and force Chinese shipyards into international competition if they wish to begin large-scale production of LNG carriers.

LNG fleet structure

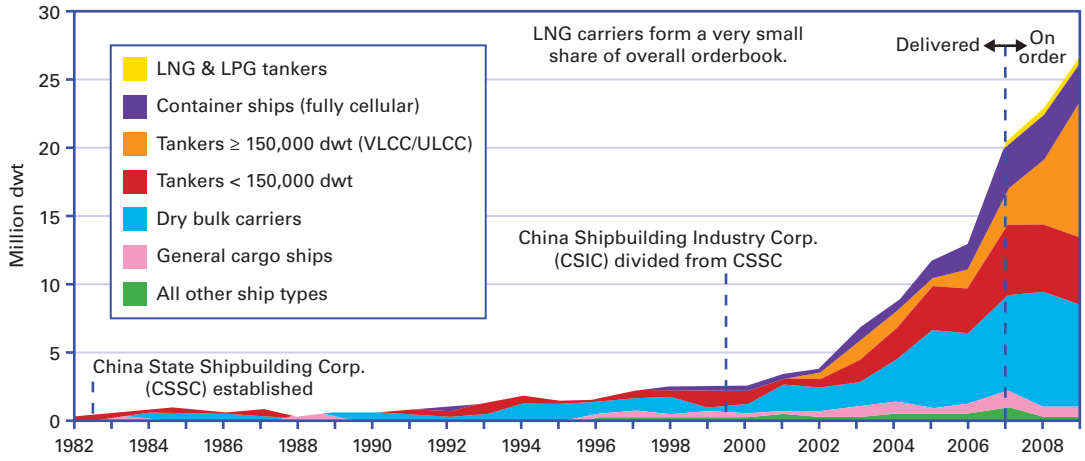
China's LNG shipping sector is at present bifurcated, with China LNG Shipping serving all terminals south of the Yangtze River and China Shipping

LNG Investment set to serve terminals north of the Yangtze.[16]

Fig. 2 shows the two companies, as well as their fleets and partners.

PRC SHIPBUILDING PRODUCTION

Fig. 3



Source: Lloyd's Sea Web

Shipbuilders' prospects

High global LNG prices have for now arrested Chinese LNG demand growth. Yet wealthier buyers—particularly Western European countries, South Korea, and Japan—continue driving world LNG demand, in turn creating ship demand.

Global LNG fleet growth has been phenomenal, averaging roughly 8%/year for the past 10 years. By 2008, the fleet may expand by a further 50% to 300 vessels. The total size of the world LNG fleet is currently very small, however, when compared with fleets of other ship types.

At July 1, 2007, there were 237 LNG carriers in service, with roughly 400 slated to be in service by 2010 (as opposed to more than 10,000 oil tankers currently in service). After 2010, construction will likely slow significantly. Industry sources say Korean yards have already begun shifting potential LNG slots back to containerships and oil tankers.

Qatari projects have been the single biggest source of LNGC newbuild orders, most of them to Korean yards. Qatar has established a moratorium on new LNG projects, however, until current projects are completed, around 2010-11, but can be expected to continue development, perhaps at a slower pace, after that.

Other new LNG exporters will eventually make significant ship orders. Leading candidates, such as Iran (unresolved nuclear program troubles), Nigeria (post-election turmoil), and possibly Russia (resource nationalism), likely are 3-4 years from becoming major LNG carrier purchasers.

By the time these countries begin ordering new LNG carriers, South Korean yards will have largely completed their Qatari orders and have open berths. The South Koreans will aggressively protect market share, since China's advantages in building bulk carriers, tankers, and other "commodity" ships are forcing South Korean yards to focus on LNGCs and other high value ships.

At present, Chinese yards lag the global state of the art in LNG building technology, have trouble meeting delivery dates, have low indigenous innovation capacity, and are internationally unproven. Korean yards are highly efficient, highly innovative, and have a more than 10-year reputation of delivering high-quality vessels on time.

On the whole, Chinese shipyards are rapidly improving. The "federal" yards run by CSSC and CSIC are progressing especially fast. Two of them, Shanghai Waigaoqiao and Dalian New Shipbuilding Heavy Industry Co., are among the world's 10 most competitive shipyards.[17] Even these top-tier yards, however, are not yet near to being globally competitive as LNGC builders.

Table 3 compares Korean and Chinese shipbuilders.

Chinese yards face a major fight to become major global LNG carrier builders. There will, however, be opportunities for them to capture LNGC market share in coming years.

CHINESE VS. SOUTH KOREAN SHIPBUILDERS

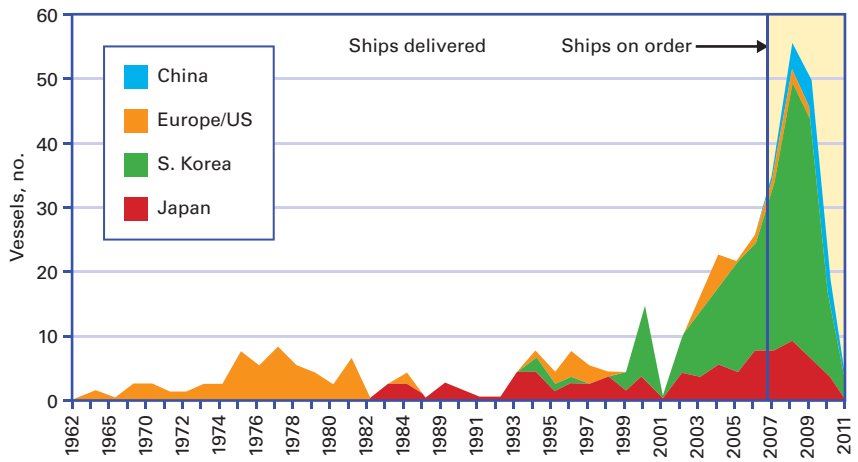
Table 3

Chinese yards	South Korean yards
Unproven as global LNGC builders.	More than 10 years as a major LNGC builder.
Chinese yards capable of building LNGCs (CSSC and CSIC) now tend to deliver ships on time.	Good "on time" reputation.
LNG vessel construction costs=~$1,100/M cu m.	LNG vessel construction costs=~$1,000-1,400/M cu m.
Entire shipbuilding sector must import 60% of ship subcomponents.	Entire shipbuilding sector must import ~15% of ship subcomponents.
Low labor costs but offset by low efficiency, Shipbuilding industry overall annual revenue per worker in 2005: $9,000*	Higher labor costs but very efficient. Shipbuilding industry overall annual revenue per worker in 2005: $480,000*

*China Ship Survey, Issue 10, 2006.

WORLD LNG TANKER PRODUCTION

Fig. 4



Source: Lloyd's Sea Web

As Japanese shipbuilders lose competitiveness, Chinese builders may be able to secure a larger share of the LNGC market.[18] Also, as ships in the current fleet near the end of their service lives, demands for replacement tonnage will create opportunities for Chinese LNGC builders.

Chinese ship designers and engineers are now researching 200,000-cu m class LNG carriers as well as LNG tank design, techniques for welding low-temperature metals, and flex-fuel engines such as those featured on new Q-Flex and Q-Max vessels.[19]

Chinese yards do not need LNG carrier orders to stay in business, as they are already very busy building tankers, bulk carriers, and other less complex ship types for which they enjoy greater international competitiveness.

Although building complex ships will play an important role in China's shipbuilding strategy in coming years, it appears that China's current desire to build LNG carriers is driven by politics rather than inherent competitive advantages. Tankers, bulk carriers, and other less complex ships will dominate Chinese ship production for at least 2 years to come (Fig. 3).

Global market influences

By raising or lowering global LNG ship demand, many factors will influence China's commercial opportunities for LNGC construction.

Factors that could drive LNG fleet growth include:

- Continued strong global economic growth.
- Rising oil prices and consumers finding ways to use gas as a substitute.
- Continued Russian gas supply manipulation driving Western Europeans toward greater LNG imports.
- Greater global pressure to use clean fuels for power generation and industrial purposes.
- US carbon emissions cap-and-trade policy driving increased natural gas demand that cannot be met with domestic supplies or Canadian imports.

Factors that could reduce LNG fleet growth include:

- Global economic slowdown.
- Softening in US gas demand or major new domestic gas discoveries.
- Political risk in gas exporters (particularly Iran and Russia) curtailing supply growth and keeping LNG prices beyond the reach of Chinese and Indian consumers.
- Russia, Iran, and other major exporters creating a "Gas OPEC".
- Clean-coal technology making major inroads and reducing the environmental imperative for gas use.
- Major developing countries failing to liberalize their internal gas markets.
- NIMBY ("not in my backyard") concerns in importing countries, particularly the US.

Reshaping global ship market?

Some Chinese analysts believe that within 10-15 years, Chinese LNG carrier builders could directly compete with South Korea. South Korea currently captures more than 70% of global LNG carrier orders, building approximately 35 LNG carriers/year.20 Chinese industry observers believe that by 2015, Chinese yards could turn out 10 LNG carriers annually.[21]

If international buyers begin ordering Chinese built LNGCs, such a build rate could be feasible. According to Lloyd's Sea Web data, South Korean yards were able to turn out 12 vessels/year within 10 years of launching their inaugural LNG carrier.

Fig. 4 illustrates how South Korea rapidly displaced Japan as an LNGC builder in the late 1990s. Many shippers note that China today resembles South Korea in the early 1990s, meaning that China is likely to continue rapidly capturing global ship market share.

Chinese yards have reshaped the global tanker and bulker ship markets. The question for the next 5-8 years is whether Chinese yards will be able to make a similar entry into the global LNGC market.

In the near future, the global shipbuilding industry might separate into two levels.

China would dominate the lower and middle ship complexity levels. South Korea would reduce its bulk carrier and tanker construction and focus on LNG carriers, FPSOs, and other high-complexity vessels. Japanese and European yards would lose badly under this scenario.

With respect to LNG tanker construction, Korean builders might build the basic ship hull and associated structures in China and then conduct final assembly in South Korea. Such an approach would cut costs while keeping core LNG shipbuilding technology out of a future competitor's hands. By

lowering South Korean LNGC building costs, this would also undercut China's shipbuilding cost advantage.

Chinese shipyards face many challenges as they strive to build LNG carriers and other complex ships. Nonetheless, it would be unwise to underestimate Chinese shipbuilders' long-term potential to become a major global threat to South Korea's dominant position in global LNG carrier construction.

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LNG

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Asian, global LNG markets in transition are defining future

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Recent changes in global LNG markets have certainly been more dramatic than changes in oil markets, making it difficult to devise a vision of the future with much confidence.

The following discussion will nevertheless set forth some likely trends, including:

1. From a seller's point of view, a mixed portfolio of sales to East and West is a likely strategy. Rich Asian customers—Japan, Korea, and Taiwan—may well be preferable to sales at the US Henry Hub (La.) and the UK's National Balancing Point. Asian buyers will buy LNG indexed to crude oil prices, and crude prices seem unlikely to crash. But Henry Hub volatility and uncertainty is a permanent feature of this market.

2. Gas in hand (as opposed to gas likely from future projects) is worth $1/MMbtu or more than future and potential gas. The sellers with final investment decision at hand can command a premium in the market.

3. The Qatari contract price offer in spring 2007 of $10-11/MMbtu is not sustainable. Within a year or so, some of this LNG may well be offered at 15-20% lower price for term buyers.

4. Henry Hub will become a more important player in pricing. Eastern buyers will pay a premium above Henry Hub for term contracts that will be oil based but with an eye on Henry Hub prices. Spot prices in Asia will be more aligned with Henry Hub by 2008-09 and may be lower than the current levels.

5. Emerging markets of China and India will have limited impact on the evolution of prices. In China, the opening up of the market to global LNG will be slow and in India, Krishna Godavari basin gas will dampen new increases in LNG demand beyond existing commitments and possible supplies from Gorgon.

6. Northwest Shelf marker of $8/MMbtu remains the best marker for Asian term contracts.

In short, the major LNG market transition which began in 2006 will be partially completed by 2009; prices might well be lower then than they are today.

Market phases

LNG markets have gone through three distinct phases:

1. Legacy contract phase. Contracts were signed heavily linked to oil prices. Earlier contracts from Indonesia did not have any S-curves and no floors and ceilings. The most expensive of these are from Indonesia to Korea and Taiwan at $10-13/MMbtu and to Japan $7.40-$8.80/MMbtu, with contracts expiring in 2010-11. (These legacy prices are not far off from the recent spot prices.) This phase lasted through 2001.

2. Low price phase. Led by China, buyers issued successful tenders and five very low price contracts with delivered prices of $3.00/MMbtu or a little higher were signed. A sixth contract was signed with KOGAS a little later after a tender with three suppliers: MLNG Tiga, Sakhalin II, and Yemen LNG. All of these contracts had a lower linkage to oil.

These were Tangguh to Fujian; NWS to Guangdong; Tangguh to POSCO/K-Power; RasGas to CPC; Oman to Osaka Gas; and KOGAS tender for MLNG, Sakhalin II, and Yemen LNG.

Also the RasGas-Petronet deal provided for an FOB price of $2.53/MMbtu for 5 years (after renegotiation), but because it escalates in a big way in later years, we have not included it in the above list.

Excited about these low prices, buyers thought this was the beginning of a new trend and sought to lower the prices even further. This proved to be a huge mistake. They lost the chance of further lower priced contracts, and indeed the market turned around in a big way.

This phase ended with KOGAS contracts in early 2005.

3. A move toward legacy contracts with higher crude linkages and higher prices. The market became extremely tight in 2006, a condition that will last at least through 2011 and beyond, but some relief will come in late 2008-09 as new supplies enter the market.

"Qatar's 48 million tonnes of western oriented supply do not have a legitimate home in Europe and the US. It simply cannot fit in the current time frame without depressing prices."

New markers

Two new markers have emerged in the East:

- NWS sales price ($8/MMbtu at Japan Crude Cocktail $60) and Qatar prices for sale to Japan and Korea ($10.50-11/MMbtu at JCC $60) for 7- to 20-year contracts. Every seller is looking to place itself between these

two markers but often look to NWS as a benchmark rather than Qatari prices.

Henry Hub prices represent prices in the world's biggest gas market—the US. While HH was in the $6-7/MMbtu range, Qatar signed term contracts of $10-11/MMbtu, and spot prices averaged at about the same levels. Indeed over the 15 months leading up to April 2007, spot prices have been based on a premium over netback from the UK's National Balancing Point and HH, whichever is higher.

Henry Hub and NBP: Convergence?

In the short term, 2007-10, HH will be less affected by crude and product prices and more by the dynamics of gas supply and demand in the US. The price of $7-8/MMbtu in second-quarter 2007 may prove a little high. Indeed, we forecast a price of $6.60/MMbtu for HH in 2007 and $7.80/MMbtu for 2008.

NBP is a much smaller market and the low price in spring 2007 of around $3.50-4.00/MMbtu compares to the average southern European price of around $7/MMbtu. How will they both be affected by Qatar's super trains entering the European market in 2009-10?

If we think of HH as an Olympic size swimming pool, we must think of NBP as a children's lap pool. Entry of large-scale LNG will affect both markets, but more so for NBP.

Indeed, Qatar's 48 million tonnes of western oriented supply do not have a legitimate home in Europe and the US. It simply cannot fit in the current time frame without depressing prices.

Eventually, NBP and southern European prices will converge, but it will take some time. Then, NBP and HH will converge as well, at least directionally. But this also takes time and Qatar's export volumes could disturb the natural progression. It is possible that Qatar's exports to the US and Europe can lead to prices lower by, say, $1-2/MMbtu, if the sellers do not carefully handle these sales.

Over the longer term, three major trends emerge:

1. Gas will continue to be priced at a discount to oil by 10-20% due to the influence of the power sector. Many suppliers argue strongly that crude oil parity should be the trend.

Only if the power sector is not a buyer of gas can crude oil parity be maintained in the medium term. Crude oil parity may be achieved in 5 to 10 years but not immediately and not in all markets.

In the future, "Asian [natural gas] prices will offer more reliable and higher absolute prices" than Henry Hub.

2. HH prices will stay roughly in the $7-9/MMbtu range in real terms through 2020. This corresponds roughly to our long-term real oil price forecast of $65/bbl (after going up to $80/bbl before dropping to $65/bbl). Of course, there will be cyclical ups and downs in the price of HH as in the price of oil. But, from a seller's and buyer's points of view, looking for long-term contracts in this range defines a useful price range as a reference point so they can negotiate the term prices accordingly.

3. A premium of perhaps 20% above HH netbacks provides adequate incentives for any exporter to divert LNG from West to East on a long-term basis.

The immediate conclusion is that term contract prices of $10-11/MMbtu for 7-20 years are too high. The buyer needs to think of these prices as outside the reasonable long-term range. Of course, LNG buyers' circumstances may dictate signing such deals, but they should be treated as exceptions.

For the seller, a purchase price of $8-9.50/MMbtu ex ship Japan must be perceived as a solid offer for the long term. The seller must not get too greedy and force unsustainable deals. We continue to believe that the NWS price sends a much more reasonable price signal to the market than the recent Qatari price to KOGAS and Chubu.

Spot prices and Henry Hub

Since HH is the closest we have to a global spot price, all spot sales around the world should have a very close correlation to HH. But, at mid 2007, the relationship is broken, primarily because of tight supply and buyers' fears of not accessing essential supplies on time.

The role of Qatar in this process, however, cannot be underestimated. It has played a key role in making HH a floor and pricing spot cargoes at a significant premium above HH.

We do not believe this picture is sustainable beyond 2008-09. HH and spot prices will be much more closely aligned.

Qatar export strategy

Qatar knows well that 48 million tonnes do not easily fit the western market in the next few years. It also knows of the desperation of the Asian buyers worried about the loss of Indonesian supplies and delays in Australia. The strategy clearly is to sell as much as possible to the East at high $10-11/MMbtu long-term prices before the Qflex and Qmax ships head to the Atlantic Basin.

Initial ambition was to sell some 10-15 million tonnes to the East by yearend 2007. This strategy has clearly failed. But, even if it had succeeded, at least 30-35 million tonnes still must go west.

Not only will these volumes reduce the price, but they also make it very difficult for Qatar to insist on a $10-11/MMbtu price to the East with a HH netback of, say, $5-6/MMbtu. The buyers simply will not accept this.

There seem two strategic options for Qatar:

1. After failing to secure large volume sales to Asia by mid 2007, assess the HH price impact of new exports and amend the strategy within a year by offering long-term contracts at NWS price of, say, $8-9/MMbtu. This could result in a significant boost in eastward diversions to as much as one third of Qatar's exports.
2. Hold tight on the higher price, do not compromise, and assume by 2010 that buyers will be back and pay the high prices.

Certainly, Qatar can do both. We believe the first strategy will be chosen and Qatar will have to compromise and lower prices. Of course, what happens to HH makes a difference. If HH goes to $4-5/MMbtu, buyers may not buy into even the first strategy, but at $6-7/MMbtu HH, these prices will be acceptable.

Eastern price vs. Western price

It is not easy to choose between a HH price and an Eastern price. One has been higher than the other in different times. Many sellers would prefer a portfolio approach with sales in both markets.

We believe that in the future, Asian prices will offer more reliable and higher absolute prices than HH will. Here are our reasons:

We trust crude oil strength in the long term more than HH strength. Crude oil prices are unlikely to crash and, while there may well be cycles, will stay in the $65/bbl range. But HH (and NBP) prices are subject to gas-to-gas competition and entry of new volumes into the market.

This means inherently being linked to crude prices is safer for a seller than being connected to HH. According to EIA forecasts, by 2015 HH in real terms will be $6/MMbtu, but crude prices will be in the mid $60s, indicating the reliability of the crude price is stronger than HH pricing.

Some people argue that Qatari exports into the US will comprise a small portion (3-7%) of consumption, making little impact on the price. According to the economic theory, prices are determined at the margin. Therefore, we believe imports will have an impact disproportionate to the size of the imported volume.

Although HH prices are likely to be fall as a result of new imports from Qatari supertrains, it is impossible to say by how much. Clearly the impact on NBP, where 17% of consumption will be imported, is much higher than HH.

Another imponderable is the US gas-supply situation and its impact on price. A number of companies in the US are convinced that the US gas production is in permanent decline. Others, including US Geological Survey, Energy Information Administration, and the National Petroleum Council believe production will rise substantially, spurred by higher oil and gas prices.

For China and India, "demand for gas has no limits at the right price, but in both countries, state electricity companies will be unwilling to pay much over $3.50-3.75/MMbtu and this will not change for many years."

These two scenarios have a big impact on the direction of HH prices. Clearly a big growth in the gas production will depress gas prices, while a drop in gas production will strengthen them. Since we do not know which of these outcomes will happen, from a seller's point of view, the comfort of oil linked Asian prices may be more reassuring than the ups and downs of HH.

Can there be a formula linking HH and Asian price? So far no such move has taken place, but if Asian prices remain higher than HH for an extended time, it is very likely that some kind of linkage will appear in the price formulas for the East. This will then protect both buyers and sellers and lead to global market pricing.

Limits of Asian appetite?

For wealthy importers—Japan, Korea, and Taiwan, some 15-20 million tonnes of diverted LNG form a limit. And Qatar is not the only supplier looking at volume diversions. There will be volumes diverted from Tangguh, Sakhalin II, and possibly others.

What about China and India? For both of these countries, demand for gas has no limits at the right price, but in both countries, state electricity companies will be unwilling to pay much over $3.50-3.75/MMbtu and this will not change for many years.

In China, the price is still set by the National Development and Reform Committee (NDRC) at the $5/MMbtu range. Even though an upward adjustment is expected, we simply cannot see China paying the same price as Japan, Korea, and Taiwan for many years.

But India is now able to accept much higher prices. In 2006, India imported 20 cargoes of spot LNG, and for 2007, spot LNG imports will likely be 40-50 cargoes. This is a substantial volume of spot cargoes amounting to about 2.4-3.0 million tonnes of LNG.

Currently sourcing spot cargoes is relatively easy due to the proper functioning of liquefaction plants, warm winter conditions in Europe, and weak demand from the rest of Asia. This trend, however, may well change the future.

Also, India's massive Krishna Godavari (KG) basin gas will be in the market by mid 2008 at a delivered price of $5-6/MMbtu. The state electricity boards are not targeted customers. This will make it difficult to expect high LNG prices to be paid by India since 1.41 bcfd (estimated 40,000 cu m/day of initial gas output from KG basin) of gas equivalent to some 11

million tonnes of LNG will be priced at equivalent delivered LNG price of $3.5-4.0/MMbtu at Hazira or Dahej. Gas volumes from the KG basin are likely to rise to 2.82 bcfd (equivalent to some 22 million tonnes of LNG) by 2011 and everyone is counting on it.

In short, the emerging markets in China and India will not support Qatar's high price strategy. The strategy simply needs to be re-examined. **LNG**

The author

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PROJECT UPDATES

LNG's share of world gas use continues to increase

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Recent forecasts of natural gas demand growth and LNG's role in it confirm the growing importance of LNG trade. And a review of world activity shows that steady growth in plants and terminals is a response to that growth.

Trends

Cedigaz, the French natural gas information agency, reported in April that world-marketed production rose 2.9% to 2.93 trillion cu m (103.4 tcf) in 2006, compared with a 2.1% increase in 2005. North American production rose 2.3% to 26.6 billion cu m (26.6 tcf) last year. Table 1 shows Cedigaz's preliminary estimates.

World gas trade rose only 2.5% to 886 bcm in 2006, compared with a 5.4%/year average growth rate over the past decade, because of stagnating pipeline exports. LNG exports, however, surged 11.7% to 211 bcm, compared with an average increase of 7.7%/year over the past 10 years.

In 2006, LNG accounted for 23.8% of all internationally traded gas volumes and a record 7.2% of total world gas consumption. European LNG imports rose 20.4% and Asian imports 10.4%, but North American imports plunged 7.3% to 16.5 bcm (582 bcf).

The International Energy Agency's Natural Gas Market Review 2007, also published in April, forecasts that primary gas consumption will increase 2.5%/year from 2,784 bcm (97 tcf) in 2004 to 3,643 bcm (128.5 tcf) in 2015, with the largest volumetric increases in the Middle East and developing Asia. Gas's share of global primary energy will remain at 21%.

The IEA scaled down its gas demand projections from last year because of higher assumptions about gas prices that will create an incentive to use coal in power generation.

As a result of massive investments in LNG projects, LNG's share of global gas demand is to grow to 10-12% by 2015 from 6% in 2004. In countries of the Organization for Economic Cooperation and Development, LNG's share could rise to 17-22% from 11%, while North America's dependence could increase to 10-12% from 6%, assuming a modest increase in domestic production.

Finally, in its Annual Energy Outlook Reference Case (April 2007), the US Energy Information Administration forecasts that LNG imports will meet much of the increased US demand for natural gas over the next 2 decades as Canadian imports decline. Total net US imports are to grow to 4.5 tcf in 2030 from 0.6 tcf in 2005, 0.2 tcf higher than in the 2006 report.

The 2007 forecast assumes that 2.4 tcf will be delivered into the four new terminals now under construction and 2.1 tcf into existing terminals (including expansions at Cove Point, Md; Elba Island, Ga., and Lake Charles, La.) Because of liquefaction project delays, however, supply constraints at several liquefaction plants and rapid growth in global LNG demand, the US LNG market will be tight until 2012.

Europe

In May 2007, National Grid Grain LNG Ltd., subsidiary of National Grid PLC, announced a third expansion of capacity at its Isle of Grain terminal that would raise capacity to 14.8 million tpy by 2010-11.

The terminal started operations in July 2005 with capacity of 3.3 million tpy. A second phase of development, currently under way, will add three storage tanks and boost capacity to 9.8 million tpy (around 2.1 bcfd) starting in 2008. Chicago Bridge & Iron NV will build the third-phase expansion, which will include another 190,000-cu m storage tank and a jetty to accommodate ships as large as 265,000 cu m.

The original capacity was booked by BP and Sonatrach for 20 years. Capacity of the second expansion was sold to Sonatrach, Centrica, and Gaz de France, while a contract for an additional 5 million tpy has been signed with E.On, Iberdrola, and Centrica

In France Shell Energy Europe and the Port of Marseille are studying development of a terminal at Fos-sur-Mer that would have initial capacity of 5.8 million tpy. Gaz de France is building a 5.8-million-tpy terminal at Fos-Cavaou (near its existing Fos-sur-Mer terminal) that is set to start up in 2008.

The Petroleum Safety Authority Norway (PSA) has given permission for deliveries to start from the single-train 4.1-million-tpy Snøhvit

World natural gas production

Table 1

Region	2006, billion cu m (tcf)	Change over 2005, %
Former Soviet Union	830.9 (29.3)	2.2
North America	754.0 (26.6)	2.3
Asia/Oceania	377.0 (13.3)	4.3
Middle East	328.2 (11.6)	5.0
Europe	291.9 (10.3)	-2.2
Africa	190.5 (6.7)	9.9
Latin America	143.3 (5.1)	4.5
Central Europe	14.3 (0.5)	-2.1
Total	**2,930.0 (103.4)**	**2.9**
Pipeline deliveries	675 (23.8)	-0.1
LNG shipments	211 (7.5)	11.7

Source: Cedigaz, 2006 Natural Gas Year in Review, 2007.

Hammerfest LNG project in December 2007, a year later than originally planned, although a few single cargoes might be shipped earlier. A cooling cargo was delivered in December 2006.

The LNG will be sold to Statoil for delivery to the Cove Point, Md., terminal, Spain's Ibedrola SA, Gaz de France, and Total. Operator Statoil is studying the feasibility of building a second train.

In the Mediterranean, the government of Cyprus will invite tenders to build and operate an offshore natural gas receiving terminal to supply a new dual-fuel power generation plant. A land-based terminal is also under consideration.

Excelerate Energy's 135,000-cu m LNG carrier Excalibur participated earlier this year in an historic ship-to-ship transfer of LNG to sister LNG regasification carrier Excelsior. The transfer occurred at sea at Scapa Flow in the Orkney Islands off northern Scotland and was preliminary to the commissioning of Excelerate's second offshore terminal, at Teesside, UK. (Photograph from Exmar NV, Antwerp)

Americas

In the US, Gaz de France and Cheniere Energy have signed 15-year agreements under which GdF can deliver 12 cargoes/year to Cheniere's Sabine Pass (Tex.) terminal, set to start up in spring 2008, and Cheniere will have the option to deliver 12 cargoes to GdF at Isle of Grain.

The deals will allow the two companies to expand their transatlantic arbitrage capacity, said the companies. Cheniere also agreed to buy up to seven cargoes ex ship from GdF in 2008 at Henry Hub (La.) prices.

In California, Gov. Arnold Schwarzenegger rejected BHP Billiton's proposal to build the Cabrillo Port regasification terminal 20 miles off Malibu. This followed rulings by the California Coastal Commission and the California State Lands Commission against awarding an offshore lease to BHP Billiton LNG for the project on environmental grounds.

In the Gulf of Mexico, Shell US Gas & Power LLC announced in April it had decided to drop plans for its proposed gravity-based Gulf Landing LNG receiving and regasification terminal off Louisiana.

Shell had gained approval for Gulf Landing from the US Maritime Administration (Marad). The proposed terminal would have had capacity to deliver 1 bcfd of natural gas to the US interstate pipeline network. Plans called for a gravity-based structure in 55 ft of water 38 miles off Louisiana on West Cameron Block 213.

In the Northeast, however, plans advanced for two offshore LNG terminals.

In April, Suez LNG Trading's Neptune project received its final license from Marad.

In May, Northeast Gateway Energy Bridge LLC, a subsidiary of Excelerate Energy LLC, received its port license from Marad. It was, according to the company, the key approval needed to begin construction in Massachusetts Bay of the second offshore LNG terminal in the US.

Excelerate Energy will build Northeast Gateway off Boston 18 miles east. Spectra Energy, formerly Duke Energy, will build a 16-mile subsea pipeline from its existing HubLine, which traverses Massachusetts Bay from Beverly to Weymouth, Mass., to the port site to transfer natural gas from the vessels into New England's gas pipeline network.

Skaugen Offshore will operate the terminal, which will use Excelerate's proprietary Energy Bridge regasification vessel (EBRV) fleet operated by Exmar NV. The port's infrastructure will feature two submerged turret loading buoys supplied by Advanced Production and Loading.

With peak deliveries of up to 800 MMcfd, Northeast Gateway can deliver about 500 MMcfd into the New England market during normal operations, said Excelerate, or about 20% of the New England market's current annual natural gas consumption.

Construction is under way to allow the terminal to begin gas deliveries into Massachusetts and the rest of New England by yearend.

Off the west coast of Florida, Höegh LNG intends to build and operate a deepwater natural gas terminal through its wholly owned US subsidiary Port Dolphin Energy. The company applied to the US Coast Guard for approval of the project, which resembles Excelerate Energy's Energy Bridge concept.

El Paso's Elba Island LNG terminal made history in December 2006 when two tankers—the British Trader and the Edouard LD—docked there. This was the first time two tankers have docked simultaneously at a US LNG import terminal. A currently planned expansion at Elba Island includes 8.4 bcf more storage capacity and 900 MMcfd of sendout capacity, effectively doubling both. It also will modify docks to accommodate larger vessels. (Photo from El Paso Corp.)

The Port Dolphin project will consist of two submerged turret unloading and mooring buoys to receive 800 MMcfd from LNG shuttle and regasification vessels (SRVs).

This announcement in April followed news that Höegh LNG and Mitsui OSK Lines had confirmed that SRVs ordered a year earlier would go onto long-term charters to Suez LNG Trading and will serve its Neptune LNG project in Massachusetts Bay, mentioned earlier.

The LNG tankers have onboard regasification systems and will be used to deliver natural gas directly into the local grid via an existing subsea pipeline. The vessels are due for delivery in 2009 and 2010.

In April, El Paso Corp.'s proposed expansion of the Elba Island LNG terminal and associated facilities near Savannah, Ga., would do minimal environmental harm, the US Federal Energy Regulatory Commission's staff said in a draft environmental impact statement.

The project includes expansion of the existing LNG terminal, about 187 miles of new pipeline in Georgia and South Carolina, a 10,000-hp compressor station in Georgia, and associated facilities. El Paso subsidiaries Southern LNG Inc., Elba Express Co. LLC, and Southern Natural Gas Co. are the sponsors.

SNG will add 8.4 bcf of storage capacity and 900 MMcfd of sendout capacity to the terminal, effectively doubling both. It also will modify docking facilities to accommodate larger vessels.

In South America, Brazil's state oil and gas company Petrobras has chartered two floating regasification and storage units (FSRUs) from Golar to begin importing LNG in mid-2008. The FSRUs will be moored at Guanabara Bay near Rio de Janeiro and off Ceara in northeast Brazil. Their peak capacities will be 500 MMcfd and 250 MMcfd, respectively.

The regasified LNG will move through underwater pipelines into Petrobras' pipeline system. Golar will work with Moss Maritime to convert the 138,000-cu m Golar Winter (built in 2004) and the 128,600-cu m Golar Spirit (1981) to FSRUs. Petrobras is considering a third terminal.

Petrobras has signed master agreements with Algeria's Sonatrach and Nigeria LNG establishing terms for the possible sale of spot cargoes and is negotiating with other companies, including Oman LNG. The LNG is needed in May-October when rainfall and hydroelectric generation are low.

Participants in Chile's first LNG project have formed GNL Quintero SA to build and operate the terminal. Partners are BG with 40%, Chile's state-owned ENAP 20%, Spain's Endesa 20%, and Chilean gas company Metrogas SA 20%.

Africa, Middle East

Equatorial Guinea LNG shipped its first cargo from the single-train 3.7-million-tpy plant on Bioko Island at the end of June 2007. Most of the capacity has been sold to BG for 17 years. A decision is still pending on a second train, which may use feedstock from neighboring Cameroon and Nigeria. Shareholders in the project are operator Marathon, Mitsui, and Marubeni.

The cost of the project has been reported at $270/tonne of annual capacity, which is very competitive in today's environment in which project costs have been reported at $600/tonne and even higher. Construction costs in the energy industries have risen strongly because of escalating raw-materials prices and tight contracting and labor markets.

In Algeria, start up of the 4.5-million-tpy Gassi Touil LNG project has been postponed to 2011 from 2009 because of commercial and technical difficulties. The vertically integrated project based on reserves in the Berkine basin in the Saharan Desert is being developed by Spain's Repsol YPF

and Gas Natural.

A delay has also been reported in construction of a 5-million-tpy train at Algeria's Skikda complex to replace the units destroyed in a 2004 explosion.

Earlier this year, Qatar surpassed Indonesia as the world's leading LNG producer and exporter. In March, RasGas stated that Qatar's vast North field would likely produce 25 bcfd by 2012, compared to then current 7 bcfd.

Qatar will soon account for 30% of the total LNG production in the world, said a RasGas director. RasGas accounts for 21 million tpy out of the 30 million tpy produced by Qatar, and by 2009, it will be producing 37 million tpy.

Also in March Qatar Petroleum and Exxon Mobil Corp. observed completion of RasGas Train 5. RasGas Co. Ltd. is a joint venture of Qatar Petroleum and ExxonMobil RasGas Inc.

RasGas Train 5, one of the largest LNG plants in the world, was completed ahead of schedule in just 29 months and under budget, said the company. Train 5 will produce 4.7 million tpy and supply gas into the northern European market.

RasGas operates five trains in Ras Laffan. In addition, RasGas is building the world's largest trains: Trains 6 and 7, each with capacity to produce 7.8 million tpy and expected to start up in 2008 and 2009.

At the end of May, Equatorial Guinea LNG Holdings Ltd. delivered the first cargo of LNG from EG LNG Train 1 on Bioko Island, Equatorial Guinea, into the 138,000-cu m Gracilis under a long-term agreement to supply 3.4 million tpy to BG Gas Marketing Ltd. The cargo was destined for Lake Charles, La. (Photograph from Marathon Oil Corp.)

Asia

In April, Pakistan GasPort Ltd. agreed with the Port Qasim Authority to develop an offshore terminal at Port Qasim, following endorsement by the central government, which has exempted the project from certain taxes.

In March, Pakistan's Associated Group signed a letter of intent with Excelerate Energy to provide a regasification vessel at Port Qasim that would unload LNG from a conventional tanker, regasify it aboard at up to 400 MMcfd, and deliver it ashore via subsea pipeline.

In May, the government of the Indian state of Maharashtra finally consented to the sale of the LNG project associated with the Ratnagiri power station. The LNG terminal, originally known as Dabhol, is still under construction. Several companies have expressed an interest in the 5-million-tpy terminal, including GAIL, Reliance Industries, Gujarat State Petroleum, and the Indian utility NTPC Ltd., formerly National Thermal Power Corp.

Also in May, China's Guangdong Dapeng LNG's terminal at Shenzhen received its first cargo. Originating in Oman's Qalhat LNG, the cargo was sold ex-ship by Mitsubishi Corp., which purchased it from Union Fenosa Gas.

PetroChina has secured final approval for the $955-million Rudong LNG import terminal in the eastern province of Jiangsu. The first phase of the LNG terminal comes on stream with a capacity of 3.5 million tpy in 2011. A second phase will add a further 2.5 million tpy.

Elsewhere in Asia, ExxonMobil, Santos, Oil Search, and Nippon Oil entered into an agreement for a pre-FEED study of a standalone LNG project in Papua New Guinea.

The project would use gas from the Hines gas and condensate field along with some smaller reserves nearby, which could support a liquefaction plant with capacity to produce up to 6.5 million tpy. This phase of the project will take the rest of 2007 when a decision will be made on any subsequent detailed FEED study, with a likely plant start-up of 2012-13.

The project Indonesia hopes will reverse its LNG production slide, Tangguh, moved ahead in second-quarter 2007. Oil & Gas Journal reported that Indonesian state-owned banks, Bank Mandiri and Bank Negara Indonesia (BNI), sought to join a new syndicate of lenders to fund remaining construction costs for the $6.5-billion LNG plant (OGJ Online, May 11, 2007).

In July 2007, BP PLC is to establish a new consortium consisting of international and domestic lenders to fund the remaining $884 million required

under original financing plans for the plant's completion.

When in operation, the Tangguh plant will supply 2.6 million tpy over 25 years to Fujian in China, with SK Power Korea taking 0.55 million tpy over 20 years; Posco Korea 0.55 million tpy over 20 years; and Sempra Energy's Costa Azul, 3.7 million tpy over 20 years.

By March 2007, construction was 70% complete and start-up was still expected by fourth-quarter 2008, if operator BP Indonesia received the outstanding financing.

Partners in the Tangguh LNG project are BP 37.16%, CNOOC 16.96%, MI Berau BV (a joint venture of Mitsubishi Corp. and INPEX Corp.) 16.30%, Nippon Oil Exploration (Berau) Ltd. (a joint venture of Nippon Oil Exploration and JOGMEC) 12.23%, KG Berau-KG Wiriagar (a joint venture of Kanematsu Corp., JOGMEC, and Mitsui & Co.) 10%, LNG Japan Corp. (a joint venture of Sumitomo Corp. and Sojitz Corp.) 7.35%.

Elsewhere in the Far East, Russian gas monopoly OAO Gazprom in April formally took control of Sakhalin-2 oil and gas development. A $19.4 billion budget for the second stage of the project was approved.

As part of an agreement reached late last year between Gazprom and Royal Dutch Shell PLC, the Russian company took a 50%-plus-one-share stake in project operator Sakhalin Energy in exchange for $7.45 billion in cash. As a result, Shell's stake was halved—to 27.5%—along with the holdings of Japanese companies Mitsui & Co. and Mitsubishi Corp., which now own 12.5% and 10%, respectively.

The four companies also yesterday approved a new budget of $19.4 billion covering the second stage of the Sakhalin-2 project, which runs until 2014. LNG production at Sakhalin will begin in 2008. **LNG**

STATISTICS

US LNG imports[1]

	bcf											
	2006						2007					
Sources	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	May	June
Algeria	3.03	2.88	—	—	—	—	2.52	—	8.67	24.45	24.76	17.12
Egypt	14.90	5.85	5.90	2.74	11.26	11.42	8.79	5.68	14.76	14.19	14.52	17.84
Equatorial Guinea	—	—	—	—	—	—	—	—	—	—	—	8.85
Nigeria	6.12	6.13	8.89	8.94	5.91	3.08	5.31	5.74	9.07	9.03	14.32	8.75
Qatar	—	—	—	—	—	—	—	—	—	—	2.93	—
Trinidad	33.35	37.12	26.67	24.48	29.93	36.62	36.63	31.14	54.33	50.87	35.62	33.50
Totals	**57.40**	**51.98**	**41.46**	**36.16**	**47.10**	**51.12**	**53.25**	**42.56**	**86.83**	**98.54**	**92.15**	**91.82**

	bcfd											
Daily[2,3]	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
2007	1.72	1.52	2.80	3.28	[4]2.97	[4]3.06	—	—	—	—	—	—
2006	1.27	1.38	1.07	1.96	2.17	2.05	1.85	1.68	1.38	1.17	1.57	1.65
2005	1.94	1.88	1.49	1.58	1.82	1.87	1.63	1.39	1.72	1.92	1.94	1.65
2004	1.74	1.78	1.57	1.62	1.63	2.10	2.38	1.83	1.84	1.63	1.36	2.05
2003	0.75	0.75	1.00	1.09	1.48	1.54	1.83	1.61	1.69	1.96	1.63	1.32
2002	0.26	0.27	0.33	0.57	0.83	0.86	0.69	0.78	0.56	0.88	0.73	0.65
2001	0.59	0.72	0.75	0.73	0.88	0.89	0.77	0.58	0.73	0.38	0.26	0.43
2000	0.41	0.35	0.48	0.57	0.43	0.49	0.86	0.74	0.68	0.79	0.64	0.58
1999	0.42	0.37	0.42	0.34	0.30	0.39	0.46	0.48	0.57	0.35	0.38	0.41
1998	0.33	0.35	0.18	0.08	0.24	0.25	0.16	0.16	0.17	0.16	0.34	0.40
5-year avg.[5]	1.19	1.23	1.09	1.36	1.58	1.68	1.46	1.24	1.31	1.35	1.18	1.22
% of avg.	144	124	257	232	211	168	127	135	106	86	133	135

	bcf											
Monthly[3]	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
2007	53.25	42.56	86.83	[4]98.54	[4]92.15	[4]91.82	—	—	—	—	—	—
2006	39.37	38.64	33.16	58.69	67.14	61.57	57.40	51.98	41.46	36.16	47.10	51.12
2005	60.28	52.70	46.22	47.43	56.36	56.07	50.48	43.10	51.57	59.47	58.09	51.10
2004	53.81	51.70	48.60	48.59	50.44	62.92	73.78	56.69	55.06	50.51	40.77	63.52
2003	23.11	21.01	31.00	32.68	45.81	46.14	56.74	50.02	50.77	60.79	49.00	41.04
2002	8.04	7.57	10.15	17.21	25.69	25.82	21.40	24.17	16.89	27.42	21.81	20.15
2001	18.21	20.10	23.25	22.01	27.14	26.59	23.91	17.91	21.83	11.73	7.85	13.21
2000	12.81	10.16	14.81	17.11	13.18	14.79	26.62	22.94	20.44	24.63	19.08	18.05
1999	13.01	10.33	13.09	10.13	9.39	11.56	14.12	15.03	16.97	10.98	11.46	12.67
1998	10.15	9.77	5.66	2.54	7.59	7.59	5.08	4.86	5.13	5.02	10.06	12.50
5-year avg.[5]	45.96	41.32	49.16	56.46	64.63	62.32	51.96	45.19	43.15	46.87	43.35	45.39
% of avg.	116	103	177	168	160	136	110	115	96	77	109	113

[1]Actual and projected as of June 8, 2007. [2]Figures do not include Puerto Rico imports. [3]1998 through May 2003 values are derived from the US Energy Information Administration. [4]Incomplete data. [5]5-year average, 2000-04.

Source: The US Waterborne LNG Report, Waterborne Energy Inc., Houston.

LNG terminals under construction*

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Terminal name, location	Owner	Start up	Receiving capacity, million tpy (expansion)	Sources	EPC contractor
Americas					
Canaport LNG, St. John, NB	Irving Oil, Repsol	2008	7.5	—	SNC-Lavalin, Saipem
Cameron LNG, near Lake Charles, La.	Sempra ENI	2008	11.8	—	Aker Kvaerner, IHI
Freeport LNG, Freeport, Tex.	Freeport LNG Investments 45%, Cheniere Energy 30%, Dow Chemical 15%, Contango Oil & Gas 10%	2009	11.8	—	Technip, Saipem, Zachry
Golden Pass, Sabine Pass, Tex.	ExxonMobil 15%; ConocoPhillips 15%, QP 70%	2009	15.6	Qatar?	CB&I
Cheniere LNG, Sabine Pass, Tex.	Cheniere; capacity reserved by Total and Chevron	2008	20.4	—	Bechtel
Energía Costa Azul, México	Sempra. Shell has half of capacity.	2008	7.7	Indonesia, Russia	Techint SA, Black & Veatch, Mitsubishi, Vinci
Quintero, Chile	ENAP 20%, BG 40%, Endesa 20%, Metrogas 20%	Late 2008	7.5	—	CB&I
Guanabara Bay, Brazil (FSRU)	Petrobras	2008	3.8	—	Golar
Offshore Ceara, Brazil (FSRU)	Petrobras	2008	1.9	—	Golar
Asia					
Fujian, China	CNOOC, Fujian Investment	2008-09	2.5 (2.5)	Indonesia	Sofregaz-Technigaz
Taichung, Taiwan	Chinese Petroleum Corp.	2009	1.7		IHI, Toa, CTCI
Dabhol, India	Ratnagiri Gas & Power	2007	2.1	Qatar (RasGas)	Whessoe, Punj Lloyd, Aker Kvaerner
Europe					
Fos-sur-Mer, France	Gaz de France	Mid-2007	6	Egypt, Nigeria, Algeria	Saipem, Sofregaz
Isola di Porto Levante, Italy (offshore)	QP, ExxonMobil, Edison	End 2007	5.8	Qatar (RasGas)	Aker Kvaerner
South Hook LNG, Milford Haven, UK	QP, ExxonMobil	2007	7.8 (15.6)	Qatar (Qatargas II)	CB&I
Dragon LNG, Milford Haven, UK	BG 50%, Petronas 30%, Petroplus 20%	2007	4.4 (6.6)	Trinidad, Egypt	Whessoe Oil & Gas Ltd. Volker Stevin

*As of May 31, 2007. Source: LNG Sourcebook, GTI, Des Plaines, Ill.

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World LNG tankers under construction

Name or hull number	Owner	Capacity, cu m	Commissioning date	Shipbuilder	Primary trade route	Propulsion[1]	Containment
LNG Owdo	BW Group	148,300	2008	Daewoo	Exports from Nigeria	S	GT No. 96
LNG Imo	BW Group	148,300	2008	Daewoo	Exports from Nigeria	S	GT No. 96
Tangguh Towuti	Sovcomflot	145,700	2007	Daewoo	Tangguh exports	S	GT No. 96
Tangguh Bratan	Sovcomflot	145,700	2008	Daewoo	Tangguh exports	S	GT No. 96
Al Jassasiya	Maran Gas Maritime	145,700	2007	Daewoo	Qatar-Europe	S	GT No. 96
Maran Gas Coronis	Golar LNG	145,700	2007	Daewoo	–	S	GT No. 96
Lerwais	Qatar Gas & Pronav	210,000	2007	Daewoo	Qatar-UK	DFDE	GT No. 96
Al Safliya	Qatar Gas & Pronav	210,000	2007	Daewoo	Qatar-UK	DFDE	GT No. 96
Duhail	Qatar Gas & Pronav	210,000	2008	Daewoo	Qatar-UK	DFDE	GT No. 96
Al Ghariya	Qatar Gas & Pronav	210,000	2007	Daewoo	Qatar-UK	DFDE	GT No. 96
Daewoo 2249	Qatargas	210,000	2008	Daewoo	Qatar-US	DFDE	GT No. 96
Daewoo 2250	Qatargas	210,000	2008	Daewoo	Qatar-US	DFDE	GT No. 96
Daewoo 2251	Qatargas	210,000	2008	Daewoo	Qatar-US	DFDE	GT No. 96
Daewoo 2252	Qatargas	210,000	2008	Daewoo	Qatar-US	DFDE	GT No. 96
Daewoo 2253	Qatargas	210,000	2008	Daewoo	Qatar-US	DFDE	GT No. 96
Explorer[2]	Exmar	150,900	2008	Daewoo	–	S	GT No. 96
Daewoo 2255	Qatargas	210,000	2008	Daewoo	US imports	M	GT No. 96
Daewoo 2256	Qatargas	210,000	2008	Daewoo	–	M	GT No. 96
Daewoo 2257	Qatargas	210,000	2008	Daewoo	–	M	GT No. 96
Daewoo 2258	BW Group	156,100	2009	Daewoo	Yemen-US	DE	GT No. 96
Daewoo 2259	BW Group	156,100	2009	Daewoo	Yemen-US	DE	GT No. 96
Daewoo 2260	Korea Line Corp.	151,800	2008	Daewoo	Russia-Korea	S	GT No. 96
Daewoo 2261	Korea Line Corp.	151,800	2008	Daewoo	Yemen-Korea	S	GT No. 96
Express[2]	Exmar	150,900	2009	Daewoo	US imports	S	GT No. 96
Daewoo 2264	Qatargas	210,000	2009	Daewoo	Qatar	M	GT No. 96
Daewoo 2265	Qatargas	210,000	2009	Daewoo	Qatar	M	GT No. 96
Daewoo 2266	Qatargas	210,000	2009	Daewoo	Qatar	M	GT No. 96
Daewoo 2267	Knutsen OAS	166,000	2010	Daewoo	–	DFDE	GT No. 96
Daewoo 2268	TMT	167,000	2009	Daewoo	–	DFDE	GT No. 96
Daewoo 2269	Knutsen OAS	166,000	2010	Daewoo	–	DFDE	GT No. 96
Exquisite[2]	Exmar	150,900	2009	Daewoo	–	S	GT No. 96
Expedient[2]	Exmar	150,900	2009	Daewoo	–	S	GT No. 96
Exemplar[2]	Exmar	150,900	2010	Daewoo	–	S	GT No. 96
Daewoo 2278	TMT Co.	171,800	2010	Daewoo	–	DFDE	GT No. 96
Daewoo 2283[2]	Qatargas	210,000	2009	Daewoo	Qatar	DFDE	GT No. 96
Daewoo 2284[2]	Qatargas	210,000	2009	Daewoo	Qatar	DFDE	GT No. 96
Daewoo 2285[2]	Qatargas	210,000	2009	Daewoo	Qatar	DFDE	GT No. 96
Daewoo 2286[2]	Qatargas	210,000	2009	Daewoo	Qatar	DFDE	GT No. 96
Hanjin Pusan 192	STX Pan Ocean	155,000	2008	Hanjin Hi	–	S	Technigaz MK III
Hanjin Pusan 193	STX Pan Ocean	155,000	2009	Hanjin Hi	–	S	Technigaz MK III
Dapeng Sun	Guangdong Dapeng LNG	147,100	2007	Hudong	Australia-China	S	GT No. 96
Dapeng Moon	Guangdong Dapeng LNG	147,100	2008	Hudong	Australia-China	S	GT No. 96

World LNG tankers under construction [continued]

Name or hull number	Owner	Capacity, cu m	Commissioning date	Shipbuilder	Primary trade route	Propulsion[1]	Containment
Hudong Zhonghua H1320A	Guangdong Dapeng LNG	147,100	2009	Hudong	Australia-China	S	GT No. 96
Hudong Zhonghua H1378A	COSCO Dalian	145,000	2008	Hudong	–		GT No. 96
Hudong Zhonghua H1379A	COSCO Dalian	145,000	2009	Hudong	–		GT No. 96
Hudong Zhonghua H1401A	COSCO Dalian	145,000	2007	Hudong	Australia-China	S	GT No. 96
Hudong Zhonghua H1402A	COSCO Dalian	145,000	2008	Hudong	Australia-China	S	GT No. 96
Clean Power	Dynacom	149,700	2007	Hyundai	–	S	Technigaz MK III
Grace Barleria	NYK	141,000	2007	Hyundai	–	S	Technigaz MK III
Grace Cosmos	NYK	141,000	2008	Hyundai	–	S	Technigaz MK III
Clean Force	Dynacom	149,700	2008	Hyundai	–	S	Technigaz MK III
British Emerald	BP	155,000	2007	Hyundai	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
British Ruby	BP	155,000	2008	Hyundai	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
British Sapphire	BP	155,000	2008	Hyundai	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
Tangguh Hiri	Teekay	155,000	2008	Hyundai	Tangguh exports	DFDE	Technigaz MK III
Al Qattara	Qatar Gas & OSG	216,200	2007	Hyundai	Qatar-UK	DFDE	Technigaz MK III
Al Gharrafa	Qatar Gas & OSG	216,200	2008	Hyundai	Qatar-UK	DFDE	Technigaz MK III
Al Thumama	Qatargas	215,000	2008	Hyundai	Qatar-US/UK	DFDE	Technigaz MK III
Al Sahla	Qatargas	215,000	2008	Hyundai	Qatar-US/UK	DFDE	Technigaz MK III
Hyundai 1875	Mitsui OSK	215,000	2008	Hyundai	–	DFDE	Technigaz MK III
Hyundai 1876	Mitsui OSK	155,000	2009	Hyundai	–	DFDE	Technigaz MK III
Hyundai 1908	Qatargas	216,000	2009	Hyundai	Qatar-US	DFDE	Technigaz MK III
Hyundai 1909	Qatargas	216,000	2009	Hyundai	Qatar-US	DFDE	Technigaz MK III
Hyundai 1910	Qatargas	216,000	2008	Hyundai	Qatar-US	DFDE	Technigaz MK III
Hyundai Samho S297	BP	155,000	2008	Hyundai Samho	Indonesia-Korea/ China/others	DFDE	Technigaz MK III
Tangguh Sago	Teekay	155,000	2009	Hyundai Samho	Tangguh exports	DFDE	Technigaz MK III
Hyundai Samho S324	Mitsui OSK	155,000	2009	Hyundai Samho	–	DFDE	Technigaz MK III
Izar Sestao 331	Knutsen OAS	138,000	2008	Izar Sestao	–	S	GT No. 96
Celestine River	K Line	145,000	2007	Kawasaki	US imports	S	Moss
Kawasaki 1588	Iino	145,000	2008	Kawasaki	US imports	S	Moss
Kawasaki 1591	Osaka Gas - NYK	153,000	2008	Kawasaki	Oman-Japan	S	Moss
Kawasaki 1592	Osaka Gas - NYK	153,000	2009	Kawasaki	–	S	Moss
Kawasaki 1593	Mitsui OSK	19,100	2007	Kawasaki	Japanese domestic trade	M	Moss
Kawasaki 1600	Tokyo LNG Tanker	145,000	2008	Kawasaki	–	S	Moss
Kawasaki 1601	Tokyo LNG Tanker	145,000	2010	Kawasaki	–	S	Moss

World LNG tankers under construction [continued]

Name or hull number	Owner	Capacity, cu m	Commissioning date	Shipbuilder	Primary trade route	Propulsion[1]	Containment
Kawasaki 1611	Tokyo LNG Tanker	153,000	2009	Kawasaki	–	S	Moss
Kawasaki 1625	NYK	145,000	2009	Kawasaki	–	S	
Kawasaki 1626	NYK	145,000	2010	Kawasaki	–	S	
Trinity Arrow	Shoei	154,200	2007	Koyo	US imports	S	GT No. 96
Koyo 2260	Shoei	154,200	2008	Koyo	–	S	GT No. 96
Koyo 2263	Mitsui O S K	154,200	2009	Koyo	–	S	GT No. 96
Koyo 2265	Mitsui O S K	154,200	2009	Koyo	–	S	GT No. 96
Mitsubishi 2219	Tokyo Electric	145,000	2008	Mitsubishi	–	S	Moss
Seri Begawan	Petronas (M I S C)	145,000	2007	Mitsubishi	Malaysian exports	S	GT No. 96
Mitsubishi 2222	Petronas (M I S C)	145,000	2008	Mitsubishi	Malaysian exports	S	GT No. 96
Seri Balhaf	Petronas (M I S C)	145,000	2008	Mitsubishi	Yemen exports	S	GT No. 96
Seri Balquis	Petronas (M I S C)	145,000	2008	Mitsubishi	Yemen exports	S	GT No. 96
Grand Elena	Sovcomflot - NYK jv	147,200	2007	Mitsubishi	Russia-Japan	S	Moss
Grand Aniva	Sovcomflot - NYK jv	147,200	2007	Mitsubishi	Russia-Japan	S	Moss
Pacific Hope	NYK	145,000	2009	Mitsubishi	–	S	Moss
Mitsubishi 2236	Tokyo Electric	145,000	2009	Mitsubishi	Russia-Japan	S	Moss
Mitsubishi 2241	Mitsui OSK - NYK	145,000	2009	Mitsubishi	Qatar-Taiwan	S	Moss
Mitsubishi 2242	Mitsui OSK - NYK	145,000	2010	Mitsubishi	Qatar-Taiwan	S	Moss
Mitsui 1681	Mitsui OSK	147,200	2008	Mitsui	Russia-Japan	S	Moss
Coral Methane	Veder, Anthony	7,500	2008	Remontowa	Norway	M	
LNG Borno	NYK	149,600	2007	Samsung	Exports from Nigeria	S	Technigaz MK III
LNG Ogun	NYK	149,600	2007	Samsung	Exports from Nigeria	S	Technigaz MK III
Methane Heather Sally	British Gas Corp.	145,000	2007	Samsung	Egypt-US	S	Technigaz MK III
Methane Alison Victoria	British Gas Corp.	145,000	2008	Samsung	Egypt-US	S	Technigaz MK III
Methane Nile Eagle	British Gas Corp.	145,000	2008	Samsung	Egypt-US	S	Technigaz MK III
Seri Angkasa	Petronas (M I S C)	145,000	2007	Samsung	Malaysia-Japan	S	Technigaz MK III
Seri Ayu	Petronas (M I S C)	145,000	2007	Samsung	Malaysia-Japan	S	Technigaz MK III
Tenbek	Qatar Gas & OSG	216,200	2007	Samsung	Qatar-UK	DFDE	Technigaz MK III
Al Hamla	Qatar Gas & OSG	216,200	2008	Samsung	Qatar-UK	DFDE	Technigaz MK III
Samsung 1607	A.P. Moller	153,000	2007	Samsung	–	DFDE	Technigaz MK III
Maersk Marib	A.P. Moller	153,000	2008	Samsung	–	DFDE	Technigaz MK III
Tangguh Foja	K Line	153,200	2008	Samsung	Tangguh exports	DFDE	Technigaz MK III
Tangguh Jaya	K Line	153,200	2008	Samsung	Tangguh exports	DFDE	Technigaz MK III
Samsung 1625	A.P. Moller	153,000	2008	Samsung	Yemen exports	DFDE	Technigaz MK III
Samsung 1626	A.P. Moller	153,000	2009	Samsung	Yemen exports	DFDE	Technigaz MK III
Samsung 1632	A.P. Moller	153,000	2009	Samsung	–	DFDE	Technigaz MK III
Samsung 1633	A.P. Moller	153,000	2009	Samsung	–	DFDE	Technigaz MK III
Tangguh Palung	K Line	153,000	2008	Samsung	Tangguh exports	S	Technigaz MK III
Samsung 1641	ChevronTexaco	154,800	2009	Samsung	ChevTex projects	DFDE	Technigaz MK III
Samsung 1642	ChevronTexaco	154,800	2009	Samsung	ChevTex projects	DFDE	Technigaz MK III
Samsung 1643	Teekay	217,000	2008	Samsung	–	DFDE	Technigaz MK III

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World LNG tankers under construction [continued]

Name or hull number	Owner	Capacity, cu m	Commissioning date	Shipbuilder	Primary trade route	Propulsion[1]	Containment
Samsung 1644	Teekay	217,000	2008	Samsung	–	DFDE	Technigaz MK III
Samsung 1645	Teekay	217,000	2008	Samsung	–	DFDE	Technigaz MK III
Samsung 1646	Teekay	217,000	2008	Samsung	–	DFDE	Technigaz MK III
Samsung 1675	Qatargas	216,200	2008	Samsung	Qatar-US/UK	DFDE	Technigaz MK III
Samsung 1676	Qatargas	216,200	2008	Samsung	Qatar-US/UK	DFDE	Technigaz MK III
Samsung 1677	Qatargas	216,200	2009	Samsung	Qatar-US/UK	DFDE	Technigaz MK III
Samsung 1686	NYK - Mitsui OSK - K Line	154,800	2009	Samsung	–	DE	Technigaz MK III
Samsung 1688[2]	Hoegh	145,000	2009	Samsung	–	DFDE	Technigaz MK III
Samsung 1689[2]	Hoegh	145,000	2010	Samsung	–	DFDE	Technigaz MK III
Samsung 1694	Qatargas	267,000	2009	Samsung	Qatar-US/UK	DFDE	Technigaz MK III
Samsung 1695	Qatargas	267,000	2009	Samsung	Qatar-US/UK	DFDE	Technigaz MK III
Samsung 1696	Qatargas	216,000	2009	Samsung	–	DFDE	Technigaz MK III
Samsung 1697	Qatargas	267,000	2009	Samsung	Qatar-US/UK	DFDE	Technigaz MK III
Samsung 1727[2]	Qatargas	267,000	2009	Samsung	Qatar	DFDE	Technigaz MK III
Samsung 1728[2]	Qatargas	267,000	2009	Samsung	Qatar	DFDE	Technigaz MK III
Samsung 1729[2]	Qatargas	267,000	2009	Samsung	Qatar	DFDE	Technigaz MK III
Samsung 1730[2]	Qatargas	267,000	2009	Samsung	Qatar	DFDE	Technigaz MK III
Samsung 1745	British Gas Corp.	170,000	2009	Samsung	–	DFDE	Technigaz MK III
Samsung 1746	British Gas Corp.	170,000	2010	Samsung	–	DFDE	Technigaz MK III
Samsung 1751	Qatargas	267,000	2009	Samsung	Qatar	DFDE	Technigaz MK III
Samsung 1752[2]	Qatargas	266,000	2009	Samsung	Qatar	DFDE	Technigaz MK III
Samsung 1753[2]	Qatargas	266,000	2010	Samsung	Qatar	DFDE	Technigaz MK III
Samsung[2]	Flex LNG	90,000	2010	Samsung	–	DFDE	unknown
Samsung[2]	Flex LNG	90,000	2011	Samsung	–	DFDE	unknown
Stx Jinhae 3008	Elcano	170,000	2010	STX Shipbuilding	–	M	
Taizhou	Skaugen, I M	10,000	2007	Taizhou Zhongyuan	Chinese domestic trade	M	
Taizhou	Skaugen, I M	10,000	2008	Taizhou Zhongyuan	Chinese domestic trade	M	
Taizhou	Skaugen, I M	10,000	2008	Taizhou Zhongyuan	Chinese domestic trade	M	
Cheikh Mokrani	Sonatrach	75,500	2007	Universal Tsu	Intra Mediterranean	S	Technigaz MK III
Cheikh Bouamama	Sonatrach	75,500	2008	Universal Tsu	Intra Mediterranean	S	Technigaz MK III

[1]S = steam; DFDE = dual-fuel diesel electric; DE= diesel electric; M = motor. [2]Regasification vessel.

Source: EA Gibson Shipbrokers Ltd., London; www.eagibson.co.uk. List current as of June 1, 2007.

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